SOUTHERN CO
Form 10-K
February 21, 2018

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

þ ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934
For the Fiscal Year Ended December 31, 2017

OR

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

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

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

Securities registered pursuant to Section 12(b) of the Act:[1]
Each of the following classes or series of securities registered pursuant to Section 12(b) of the Act is listed on the New York Stock Exchange.

| Title of each class | Registrant |
|---|---|
| Common Stock, $5 par value | The Southern Company |
| Junior Subordinated Notes, $25 denominations<br>6.25% Series 2015A due 2075<br>5.25% Series 2016A due 2076<br>5.25% Series 2017B due 2077 | |
| Class A preferred stock, cumulative, $25 stated capital<br>5.00% Series | Alabama Power Company |
| Junior Subordinated Notes, $25 denominations<br>5.00% Series 2017A due 2077 | Georgia Power Company |
| Depositary preferred shares, each representing one-fourth of a share of preferred stock, cumulative, $100 par value<br>5.25% Series | Mississippi Power Company |
| Senior Notes<br>1.000% Series 2016A due 2022<br>1.850% Series 2016B due 2026 | Southern Power Company |

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

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

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

(1) As of December 31, 2017.

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

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

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

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

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

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

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

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

If an emerging growth company, indicate by check mark if the registrant has elected not to use the extended transition period for complying with any new or revised financial accounting standards provided pursuant to Section 13(a) of the Exchange Act. ¨

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

Aggregate market value of The Southern Company's common stock held by non-affiliates of The Southern Company at June 30, 2017: $47.9 billion. All of the common stock of the other registrants is held by The Southern Company. A description of each registrant's common stock follows:

| Registrant | Description of Common Stock | Shares Outstanding at January 31, 2018 |
|---|---|---|
| The Southern Company | Par Value $5 Per Share | 1,008,159,482 |
| Alabama Power Company | Par Value $40 Per Share | 30,537,500 |
| Georgia Power Company | Without Par Value | 9,261,500 |
| Gulf Power Company | Without Par Value | 7,392,717 |
| Mississippi Power Company | Without Par Value | 1,121,000 |
| Southern Power Company | Par Value $0.01 Per Share | 1,000 |
| Southern Company Gas | Par Value $0.01 Per Share | 100 |

Documents incorporated by reference: specified portions of The Southern Company's Definitive Proxy Statement on Schedule 14A relating to the 2018 Annual Meeting of Stockholders are incorporated by reference into PART III. In addition, specified portions of the Definitive Information Statements on Schedule 14C of Alabama Power Company and Mississippi Power Company relating to each of their respective 2018 Annual Meetings of Shareholders are incorporated by reference into PART III.

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

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

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DEFINITIONS

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

| Term | Meaning |
|---|---|
| Alabama Power | Alabama Power Company |
| Bcf | Billion cubic feet |
| CCR | Coal combustion residuals |
| Clean Air Act | Clean Air Act Amendments of 1990 |
| $CO_2$ | Carbon dioxide |
| Cooperative Energy | Electric cooperative in Mississippi |
| Dalton | 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 |
| DOE | U.S. Department of Energy |
| Duke Energy Florida | Duke Energy Florida, LLC |
| EMC | Electric membership corporation |
| 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 |
| FERC | Federal Energy Regulatory Commission |
| FMPA | Florida Municipal Power Agency |
| Georgia Power | Georgia Power Company |
| Gulf Power | Gulf Power Company |
| IBEW | International Brotherhood of Electrical Workers |
| IGCC | Integrated coal gasification combined cycle, the technology originally approved for Mississippi Power's Kemper County energy facility (Plant Ratcliffe) |
| IIC | Intercompany Interchange Contract |
| Internal Revenue Code | Internal Revenue Code of 1986, as amended |
| IPP | Independent Power Producer |
| IRP | Integrated Resource Plan |
| KUA | Kissimmee Utility Authority |
| KW | Kilowatt |
| KWH | Kilowatt-hour |
| MEAG Power | Municipal Electric Authority of Georgia |
| Merger | The merger, effective July 1, 2016, of a wholly-owned, direct subsidiary of Southern Company with and into Southern Company Gas, with Southern Company Gas continuing as the surviving corporation and a wholly-owned, direct subsidiary of Southern Company |
| Mississippi Power | Mississippi Power Company |
| MW | Megawatt |
| natural gas distribution utilities | Southern Company Gas' seven natural gas distribution utilities (Nicor Gas, Atlanta Gas Light Company, Virginia Natural Gas, Elizabethtown Gas, Florida City Gas, Chattanooga Gas Company, and Elkton Gas) |
| Nicor Gas | Northern Illinois Gas Company, a wholly-owned subsidiary of Southern Company Gas |
| NRC | U.S. Nuclear Regulatory Commission |
| NYSE | New York Stock Exchange |
| OPC | Oglethorpe Power Corporation (an Electric Membership Corporation) |
| OUC | Orlando Utilities Commission |

DEFINITIONS
(continued)

| Term | Meaning |
|---|---|
| PATH Act | Protecting Americans from Tax Hikes Act |
| Plant Vogtle Units 3 and 4 | Two new nuclear generating units under construction at Georgia Power's Plant Vogtle |
| power pool | The operating arrangement whereby the integrated generating resources of the traditional electric operating companies and Southern Power (excluding subsidiaries) are subject to joint commitment and dispatch in order to serve their combined load obligations |
| PowerSecure | PowerSecure Inc. |
| PowerSouth | PowerSouth Energy Cooperative |
| 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 |
| registrants | Southern Company, Alabama Power, Georgia Power, Gulf Power, Mississippi Power, Southern Power Company, and Southern Company Gas |
| RUS | Rural Utilities Service |
| SCS | Southern Company Services, Inc. (the Southern Company system service company) |
| SEC | Securities and Exchange Commission |
| SEGCO | Southern Electric Generating Company |
| SEPA | Southeastern Power Administration |
| SERC | Southeastern Electric Reliability Council |
| Southern Company | The Southern Company |
| 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 | Southern Company, the traditional electric operating companies, Southern Power, Southern Company Gas (as of July 1, 2016), SEGCO, Southern Nuclear, SCS, Southern Linc, PowerSecure (as of May 9, 2016), and other subsidiaries |
| Southern Holdings | Southern Company Holdings, Inc. |
| Southern Linc | Southern Communications Services, Inc. |
| Southern Nuclear | Southern Nuclear Operating Company, Inc. |
| Southern Power | Southern Power Company and its subsidiaries |
| 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 |
| traditional electric operating companies | Alabama Power, Georgia Power, Gulf Power, and Mississippi Power |
| Virginia Natural Gas | Virginia Natural Gas, Inc. |
| Vogtle Owners | Georgia Power, OPC, MEAG Power, and Dalton |
| Westinghouse | Westinghouse Electric Company LLC |

CAUTIONARY STATEMENT REGARDING
FORWARD-LOOKING INFORMATION

This Annual Report on Form 10-K contains forward-looking statements. Forward-looking statements include, among other things, statements concerning regulated rates, the strategic goals for the wholesale business, customer and sales growth, economic conditions, fuel and environmental cost recovery and other rate actions, current and proposed environmental regulations and related compliance plans and estimated expenditures, pending or potential litigation matters, access to sources of capital, projections for the qualified pension plans, postretirement benefit plans, and nuclear decommissioning trust fund contributions, financing activities, completion dates of construction projects, 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 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 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 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;
- 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 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 Southern Company and Southern Company Gas will be greater than expected;
- the ability of counterparties of Southern Company and its subsidiaries to make payments as and when due and to perform as required;
- the ability to obtain new short- and long-term contracts with wholesale customers;
- the direct or indirect effect on the Southern Company system's business resulting from cyber intrusion or physical attack and the threat of physical attacks;
- interest rate fluctuations and financial market conditions and the results of financing efforts;
- changes in Southern Company's and any of its subsidiaries' credit ratings, including impacts on interest rates, access to capital markets, and collateral requirements;
- the impacts of any sovereign financial issues, including impacts on interest rates, access to capital markets, impacts on foreign currency exchange rates, counterparty performance, and the economy in general, as well as potential impacts on the benefits of the DOE loan guarantees;
- the ability of Southern Company's electric utilities to obtain additional generating capacity (or sell excess generating capacity) at competitive prices;
- catastrophic events such as fires, earthquakes, explosions, floods, tornadoes, hurricanes and other storms, droughts, pandemic health events such as influenzas, or other similar occurrences;
- the direct or indirect effects on the Southern Company system's business resulting from incidents affecting the U.S. electric grid, natural gas pipeline infrastructure, or operation of generating or storage resources;
- 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 filed by the registrants from time to time with the SEC.

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

PART I

Item 1. BUSINESS

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

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

Georgia Power was incorporated under the laws of the State of Georgia on June 26, 1930.

Gulf Power is a Florida corporation that has had a continuous existence since it was originally organized under the laws of the State of Maine on November 2, 1925. Gulf Power became a Florida corporation after being domesticated under the laws of the State of Florida on November 2, 2005.

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

In addition, 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 Power Company is a corporation organized under the laws of Delaware on January 8, 2001. The term "Southern Power" when used herein refers to Southern Power Company and its subsidiaries while the term "Southern Power Company" when used herein refers only to the parent company.

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. Southern Company Gas is also involved in several other businesses that are complementary to the distribution of natural gas. Southern Company Gas was incorporated under the laws of the State of Georgia on November 27, 1995 for the primary purpose of becoming the holding company for Atlanta Gas Light Company, which was founded in 1856. See "The Southern Company System – Southern Company Gas" herein for additional information regarding agreements entered into by a wholly-owned subsidiary of Southern Company Gas to sell two of its natural gas distribution utilities.

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.

Alabama Power and Georgia Power each own 50% of the outstanding common stock of SEGCO. SEGCO is an operating public utility company that owns electric generating units with an aggregate capacity of 1,020 MWs at Plant Gaston on the Coosa River near Wilsonville, Alabama. Alabama Power and Georgia Power are each entitled to one-half of SEGCO's capacity and energy. Alabama Power acts as SEGCO's agent in the operation of SEGCO's units and furnishes fuel to SEGCO for its units.

Segment information for Southern Company and Southern Company Gas is included in Note 13 to the financial statements of Southern Company and Note 12 to the financial statements of Southern Company Gas in Item 8 herein.
The registrants' Annual Reports on Form 10-K, Quarterly Reports on Form 10-Q, Current Reports on Form 8-K, and any amendments to those reports are made available on Southern Company's website, free of charge, as soon as reasonably practicable after such material is electronically filed with or furnished to the SEC. Southern Company's internet address is www.southerncompany.com.

The Southern Company System

Traditional Electric Operating Companies

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

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

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

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

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

Southern Power

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

Southern Power Company directly owns and manages generation assets primarily in the Southeast, which are included in the power pool, and has various subsidiaries, which were created to own and operate natural gas and renewable generation facilities either wholly or in partnership with various third parties. As of December 31, 2017, Southern Power's generation fleet totaled 12,940 MWs of nameplate capacity in commercial operation (including 5,152 MWs owned by its subsidiaries). In addition, Southern Power Company has other subsidiaries that are pursuing additional natural gas generation and other development opportunities. The generation assets of Southern Power Company's subsidiaries are not included in the power pool.

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

In September 2017, Southern Power began a legal entity reorganization of various direct and indirect subsidiaries that own and operate substantially all of the 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. Southern Power is pursuing the sale of a 33% equity interest in the newly-formed holding company owning these solar assets, which, if successful, is expected to close in the middle of 2018. The ultimate outcome of this matter cannot be determined at this time.

See PROPERTIES in Item 2 herein, Note 11 to the financial statements of Southern Power in Item 8 herein, and Note 12 to the financial statements of Southern Company under "Southern Power" in Item 8 herein for additional information regarding Southern Power's acquisitions, construction, and development projects.

Southern Power calculates an investment coverage ratio for its generating assets based on the ratio of investment under contract to total investment using the respective generation facilities' net book value (or expected in-service value for facilities under construction or being acquired) as the investment amount. With the inclusion of the PPAs and investments associated with the wind and natural-gas fired facilities currently under construction and the Gaskell West 1 solar project, which was acquired subsequent to December 31, 2017, as well as other capacity and energy contracts, Southern Power has an average investment coverage ratio of 91% through 2022 and 89% through 2027, with an average remaining contract duration of approximately 15 years.

Southern Power's natural gas and biomass sales are primarily through long-term PPAs that consist of two types of agreements. The first type, referred to as a unit or block sale, is a customer purchase from a dedicated plant unit where all or a portion of the generation from that unit is reserved for that customer. Southern Power typically has the ability to serve the unit or block sale customer from an alternate resource. The second type, referred to as requirements service, provides that Southern Power serves the customer's capacity and energy requirements from a combination of the customer's own generating units and from Southern Power resources not dedicated to serve unit or block sales. Southern Power has rights to purchase power provided by the requirements customers' resources when economically viable. Capacity charges that form part of the PPA payments are designed to recover fixed and variable operations and maintenance costs based on dollars-per-kilowatt year and to provide a return on investment.

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

The following tables set forth Southern Power's PPAs as of December 31, 2017:

Block Sales PPAs

| Facility/Source | Counterparty | MWs[1] | Contract Term |
|---|---|---|---|
| Addison Units 1 and 3 | Georgia Power | 297 | through May 2030 |
| Addison Unit 2 | MEAG Power | 149 | through April 2029 |
| Addison Unit 4 | Georgia Energy Cooperative | 146 | through May 2030 |
| Cleveland County Unit 1 | North Carolina Electric Membership Corporation (NCEMC) | 45-180 | through Dec. 2036 |
| Cleveland County Unit 2 | NCEMC | 183 | through Dec. 2036 |
| Cleveland County Unit 3 | North Carolina Municipal Power Agency 1 | 183 | through Dec. 2031 |
| Cleveland County Unit 4 | PJM Interconnection LLC[2] | 183 | June 2020 – May 2021 |
| Dahlberg Units 1, 3, and 5 | Cobb EMC | 224 | through Dec. 2026 |
| Dahlberg Units 2, 6, 8, and 10 | Georgia Power | 298 | through May 2025 |
| Dahlberg Unit 4 | Georgia Power | 74 | through May 2030 |
| Franklin Unit 1 | Duke Energy Florida | 434 | through May 2021 |
| Franklin Unit 2 | Morgan Stanley Capital Group | 250 | through Dec. 2025 |
| Franklin Unit 2 | Jackson EMC | 60-65 | through Dec. 2035 |
| Franklin Unit 2 | GreyStone Power Corporation | 35-40 | through Dec. 2035 |
| Franklin Unit 2 | Cobb EMC | 100 | through Dec. 2026 |
| Franklin Unit 3 | Morgan Stanley Capital Group | 200 | through Dec. 2027 |
| Franklin Unit 3 | City of Dalton, Georgia | 70 | through Dec. 2027 |
| Harris Unit 1 | Georgia Power | 628 | through May 2030 |
| Harris Unit 2 | Georgia Power | 657 | through May 2019 |
| Harris Unit 2 | Alabama Municipal Electric Authority[3] | 25 | Jan. 2020 – Dec. 2025 |
| Mankato | Northern States Power Company | 375 | through June 2026 |
| Mankato | Northern States Power Company | 345 | June 2019 – May 2039[4] |
| Nacogdoches | City of Austin, Texas | 100 | through May 2032 |
| NCEMC PPA[5] | EnergyUnited | 100 | through Dec. 2021 |
| Oleander Units 2, 3, and 4 | Seminole Electric Cooperative | 466 | through Dec. 2021 |
| Oleander Unit 5 | FMPA | 157 | through Dec. 2027 |
| Rowan CT Unit 1 | North Carolina Municipal Power Agency 1 | 150 | through Dec. 2030 |
| Rowan CT Unit 2 | PJM Interconnection LLC[2] | 154 | June 2020 – May 2021 |
| Rowan CT Units 2 and 3 | EnergyUnited | 100-175 | Jan. 2022 – Dec. 2025 |
| Rowan CT Unit 3 | EnergyUnited | 113 | through Dec. 2023 |
| Rowan CC Unit 4 | EnergyUnited | 23-328 | through Dec. 2025 |

Block Sales PPAs (continued)

| Facility/Source | Counterparty | MWs[1] | Contract Term |
|---|---|---|---|
| Rowan CC Unit 4 | Duke Energy Progress, LLC | 150 | through Dec. 2019 |
| Rowan CC Unit 4 | Century Aluminum[6] | 158 | through Dec. 2018 |
| Stanton Unit A | OUC | 342 | through Sept. 2033 |
| Stanton Unit A | FMPA | 85 | through Sept. 2033 |
| Wansley Unit 7 | Jacksonville Electric Authority | 200 | through Dec. 2019 |

(1) The MWs and related facility units may change due to unit rating changes or assignment of units to contracts.
(2) Amount sold into PJM capacity market.
(3) Alabama Municipal Electric Authority will also be served by Plant Franklin Unit 1 through December 2019.
(4) Subject to commercial operation of the 345-MW expansion project.
(5) Represents sale of power purchased from NCEMC under a PPA.
(6) Century Aluminum PPA is partially served by Plant Franklin Unit 3.

Requirements Services PPAs

| Counterparty | MWs[1] | Contract Term |
|---|---|---|
| Nine Georgia EMCs | 294-376 | through Dec. 2024 |
| Sawnee EMC | 267-639 | through Dec. 2027 |
| Cobb EMC | 0-170 | through Dec. 2026 |
| Flint EMC | 136-360 | through Dec. 2024 |
| City of Dalton, Georgia | 92 | through Dec. 2027 |
| EnergyUnited | 78-159 | through Dec. 2025 |
| City of Blountstown, Florida | 10 | through April 2022 |

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

Solar/Wind PPAs

| Facility | Counterparty | MWs[1] | Contract Term |
|---|---|---|---|
| Solar | | | |
| Adobe | Southern California Edison Company | 20 | through June 2034 |
| Apex | Nevada Power Company | 20 | through Dec. 2037 |
| Boulder 1[2] | Nevada Power Company | 100 | through Dec. 2036 |
| Butler | Georgia Power | 100 | through Dec. 2046 |
| Butler Solar Farm | Georgia Power | 20 | through Feb. 2036 |
| Calipatria | San Diego Gas & Electric Company | 20 | through Feb. 2036 |
| Campo Verde | San Diego Gas & Electric Company | 139 | through Oct. 2033 |
| Cimarron | Tri-State Generation and Transmission Association, Inc. | 30 | through Dec. 2035 |
| Decatur County | Georgia Power | 19 | through Dec. 2035 |
| Decatur Parkway | Georgia Power | 80 | through Dec. 2040 |
| Desert Stateline[2] | Southern California Edison Company | 300 | through Sept. 2036 |
| East Pecos | Austin Energy | 119 | through April 2032 |
| Garland A[2] | Southern California Edison Company | 20 | through Sept. 2036 |
| Garland[2] | Southern California Edison Company | 180 | through Oct. 2031 |
| Granville | Duke Energy Progress, LLC | 2 | through Oct. 2032 |
| Henrietta[2] | Pacific Gas & Electric Company | 100 | through Sept. 2036 |
| Imperial Valley[2] | San Diego Gas & Electric Company | 150 | through Nov. 2039 |

Solar/Wind PPAs (continued)

| Facility | Counterparty | MWs(1) | Contract Term |
|---|---|---|---|
| Lamesa | City of Garland, Texas | 102 | through April 2032 |
| Lost Hills Blackwell(2) | City of Roseville, California & Pacific Gas & Electric Company | 32 | through Dec. 2043 |
| Macho Springs | El Paso Electric Company | 50 | through May 2034 |
| Morelos | Pacific Gas & Electric Company | 15 | through Feb. 2036 |
| North Star(2) | Pacific Gas & Electric Company | 60 | through June 2035 |
| Pawpaw | Georgia Power | 30 | through March 2046 |
| Roserock(2) | Austin Energy | 157 | through Nov. 2036 |
| Rutherford | Duke Energy Carolinas, LLC | 75 | through Dec. 2031 |
| Sandhills | Cobb EMC | 111 | through Oct. 2041 |
| Sandhills | Flint EMC | 15 | through Oct. 2041 |
| Sandhills | Sawnee EMC | 15 | through Oct. 2041 |
| Sandhills | Middle Georgia and Irwin EMC | 2 | through Oct. 2041 |
| Spectrum | Nevada Power Company | 30 | through Dec. 2038 |
| Tranquillity(2) | Shell Energy North America (US), LP | 204 | through Nov. 2019 |
| Tranquillity(2) | Southern California Edison Company | 204 | Dec. 2019 – Nov. 2034 |
| Wind | | | |
| Bethel | Google Inc. | 225 | through Jan. 2029 |
| Cactus Flats(3) | General Mills, Inc. | 98 | Aug. 2018 – July 2034 |
| Cactus Flats(3) | General Motors Company | 50 | Aug. 2018 – July 2031 |
| Grant Plains | Oklahoma Municipal Power Authority | 41 | Jan. 2020 – Dec. 2039 |
| Grant Plains | Steelcase Inc. | 25 | through Dec. 2028 |
| Grant Plains | Allianz Risk Transfer (Bermuda) Ltd. | 81-122 | through March 2027 |
| Grant Wind | East Texas Electric Cooperative | 50 | through March 2036 |
| Grant Wind | Northeast Texas Electric Cooperative | 50 | through March 2036 |
| Grant Wind | Western Farmers Electric Cooperative | 50 | through March 2036 |
| Kay Wind | Westar Energy Inc. | 200 | through Dec. 2035 |
| Kay Wind | Grand River Dam Authority | 99 | through Dec. 2035 |
| Passadumkeag | Western Massachusetts Electric Company | 40 | through June 2031 |
| Salt Fork Wind | City of Garland, Texas | 150 | through Nov. 2030 |
| Salt Fork Wind | Salesforce.com, Inc. | 24 | through Nov. 2028 |
| Tyler Bluff Wind | The Proctor & Gamble Company | 96 | through Dec. 2028 |
| Wake Wind(2) | Equinix Enterprises, Inc. | 100 | through Oct. 2028 |
| Wake Wind(2) | Owens Corning | 125 | through Oct. 2028 |

(1) MWs shown are for 100% of the PPA, which is based on demonstrated capacity of the facility.
(2) Facility is the subject of a partnership where Southern Power is the majority member. See PROPERTIES in Item 2 herein for additional information.
(3) Subject to commercial operation.

Purchased Power

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

See MANAGEMENT'S DISCUSSION AND ANALYSIS – FUTURE EARNINGS POTENTIAL – "Power Sales Agreements" and "Acquisitions" of Southern Power in Item 7 herein and Note 11 to the financial statements of Southern Power in Item 8 herein for additional information.

For the year ended December 31, 2017, approximately 11.3% of Southern Power's revenues were derived from Georgia Power. Southern Power actively pursues replacement PPAs prior to the expiration of its current PPAs and anticipates that the revenues attributable to one customer may be replaced by revenues from a new customer; however, the expiration of any of Southern Power's current PPAs without the successful remarketing of a replacement PPA could have a material negative impact on Southern Power's earnings but is not expected to have a material impact on Southern Company's earnings.

Southern Company Gas

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

Gas distribution operations, the largest segment of Southern Company Gas' business, operates, constructs, and maintains 82,000 miles of natural gas pipelines and 14 storage facilities, with total capacity of 158 Bcf, to provide natural gas to residential, commercial, and industrial customers. Gas distribution operations serves approximately 4.6 million customers across seven states and has rates of return that are regulated by each individual state in return for exclusive franchises.

On October 15, 2017, Southern Company Gas subsidiary, Pivotal Utility Holdings Inc., 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 Board of Public Utilities, 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 Board of Public Utilities 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.

Gas marketing services is comprised of SouthStar Energy Services, LLC (SouthStar) and Nicor Energy Services Company (doing business as Pivotal Home Solutions) and provides natural gas commodity and related services to customers in competitive markets or markets that provide for customer choice. SouthStar, serving approximately 774,000 natural gas commodity customers, markets gas to residential, commercial, and industrial customers and offers energy-related products that provide natural gas price stability and utility bill management. Pivotal Home Solutions, serving approximately 1.2 million service contracts, provides a suite of home protection products and services that offers homeowners predictability regarding their energy service delivery, systems, and appliances.

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

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

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

Other Businesses

PowerSecure, which was acquired by Southern Company in May 2016, provides products and services in the areas of distributed energy infrastructure, energy efficiency, and utility infrastructure.

Southern Holdings is an intermediate holding subsidiary, primarily for Southern Company's investments in leveraged leases and energy-related funds and companies, and also for other electric and natural gas products and services.
Southern Linc provides digital wireless communications for use by Southern Company and its subsidiary companies and also markets these services to the public. Southern Linc delivers multiple wireless communication options including push to talk, cellular service, text messaging, wireless internet access, and wireless data. Its system covers approximately 127,000 square miles in the Southeast. Southern Linc also provides fiber optics services within the Southeast through its subsidiary, Southern Telecom, Inc.
These efforts to invest in and develop new business opportunities may offer potential returns exceeding those of rate-regulated operations. However, these activities often involve a higher degree of risk.

Construction Programs

The subsidiary companies of Southern Company are engaged in continuous construction programs to accommodate existing and estimated future loads on their respective systems. For estimated construction and environmental expenditures for the periods 2018 through 2022, see MANAGEMENT'S DISCUSSION AND ANALYSIS – FINANCIAL CONDITION AND LIQUIDITY – "Capital Requirements and Contractual Obligations" of Southern Company, each traditional electric operating company, Southern Power, and Southern Company Gas in Item 7 herein. The Southern Company system's construction program consists of capital investment and capital expenditures to comply with environmental laws and regulations. The traditional electric operating companies also anticipate 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 Southern Company system's asset retirement obligation liabilities. In 2018, the construction program is expected to be apportioned approximately as follows:

| | Southern Company system[a][b] | Alabama Power | Georgia Power[a] | Gulf Power | Mississippi Power |
|---|---|---|---|---|---|
| | (in billions) | | | | |
| New generation | $1.3 | $ — | $ 1.3 | $ — | $ — |
| Environmental compliance[c] | 1.1 | 0.6 | 0.5 | 0.1 | — |
| Generation maintenance | 0.9 | 0.5 | 0.2 | 0.1 | 0.1 |
| Transmission | 0.9 | 0.3 | 0.5 | — | — |
| Distribution | 1.2 | 0.5 | 0.5 | 0.1 | 0.1 |
| Nuclear fuel | 0.3 | 0.1 | 0.2 | — | — |
| General plant | 0.5 | 0.2 | 0.2 | — | — |
| | 6.0 | 2.2 | 3.3 | 0.3 | 0.2 |
| Southern Power[d] | 1.3 | | | | |
| Southern Company Gas[e] | 1.7 | | | | |
| Other subsidiaries | 0.4 | | | | |
| Total[a] | $9.4 | $ 2.2 | $ 3.3 | $ 0.3 | $ 0.2 |

(a) Totals may not add due to rounding.

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

(c) Reflects cost estimates for environmental regulations. These estimated expenditures do not include any potential compliance costs associated with the regulation of $CO_2$ emissions from fossil-fuel-fired electric generating units or costs associated with closure and groundwater monitoring under the CCR Rule. See MANAGEMENT'S DISCUSSION AND ANALYSIS – FUTURE EARNINGS POTENTIAL – "Environmental Matters – Environmental Laws and Regulations" and FINANCIAL CONDITION AND LIQUIDITY – "Capital Requirements and Contractual Obligations" of Southern Company and each traditional electric operating company in Item 7 herein for additional information.

(d) Includes approximately $0.9 billion for planned expenditures for plant acquisitions and placeholder growth, which may vary materially due to market opportunities and Southern Power's ability to execute its growth strategy.

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

"The Southern Company System – Southern Company Gas" herein for additional information regarding agreements entered into by a wholly-owned subsidiary of Southern Company Gas to sell two of its natural gas distribution utilities. Projected capital expenditures of $0.1 billion related to these two natural gas distribution utilities are excluded from the amounts above.

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.

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. See Note 3 to the financial statements of Southern Company and Georgia Power under "Nuclear Construction" and "Retail Regulatory Matters – Nuclear Construction," respectively, in Item 8 herein for additional information regarding Georgia Power's construction of Plant Vogtle Units 3 and 4.

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

Financing Programs

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

Fuel Supply

Electric

The traditional electric operating companies' and SEGCO's supply of electricity is primarily fueled by natural gas and coal. Southern Power's supply of electricity is primarily fueled by natural gas. See MANAGEMENT'S DISCUSSION AND ANALYSIS – RESULTS OF OPERATION – "Electricity Business – Fuel and Purchased Power Expenses" of Southern Company and MANAGEMENT'S DISCUSSION AND ANALYSIS – RESULTS OF OPERATION – "Fuel and Purchased Power Expenses" of each traditional electric operating company in Item 7 herein for information regarding the electricity generated and the average cost of fuel in cents per net KWH generated for the years 2015 through 2017.

The traditional electric operating companies have agreements in place from which they expect to receive substantially all of their 2018 coal burn requirements. These agreements have terms ranging between one and four years. In 2017, the weighted average sulfur content of all coal burned by the traditional electric operating companies was 1.12%. This sulfur level, along with banked and purchased sulfur dioxide allowances, allowed the traditional electric operating companies to remain within limits set by Phase I of the Cross-State Air Pollution Rule (CSAPR) under the Clean Air Act. In 2017, the Southern Company system did not purchase any sulfur dioxide allowances, annual nitrogen oxide emission allowances, or seasonal nitrogen oxide emission allowances from the market. As any additional environmental regulations are proposed that impact the utilization of coal, the traditional electric operating companies' fuel mix will be monitored to help ensure that the traditional electric operating companies remain in compliance with applicable laws and regulations. Additionally, Southern Company and the traditional electric operating companies will continue to evaluate the need to purchase additional emissions allowances, the timing of capital expenditures for emissions control equipment, and potential unit retirements and replacements. See MANAGEMENT'S DISCUSSION

AND ANALYSIS – FUTURE EARNINGS POTENTIAL – "Environmental Matters" of Southern Company, each traditional electric operating company, and Southern Power in Item 7 herein for additional information on environmental matters.

SCS, acting on behalf of the traditional electric operating companies and Southern Power Company, has agreements in place for the natural gas burn requirements of the Southern Company system. For 2018, SCS has contracted for 510 Bcf of natural gas supply under agreements with remaining terms up to 15 years. In addition to natural gas supply, SCS has contracts in place

for both firm natural gas transportation and storage. Management believes these contracts provide sufficient natural gas supplies, transportation, and storage to ensure normal operations of the Southern Company system's natural gas generating units.
Alabama Power and Georgia Power have multiple contracts covering their nuclear fuel needs for uranium, conversion services, enrichment services, and fuel fabrication. The uranium, conversion services, and fuel fabrication contracts are for terms of less than 10 years with varying expiration dates. The term lengths for the enrichment services contracts are for less than 15 years with varying expiration dates. Management believes suppliers have sufficient nuclear fuel production capability to permit the normal operation of the Southern Company system's nuclear generating units.
Changes in fuel prices to the traditional electric operating companies are generally reflected in fuel adjustment clauses contained in rate schedules. See "Rate Matters – Rate Structure and Cost Recovery Plans" herein for additional information. Southern Power's natural gas and biomass PPAs generally provide that the counterparty is responsible for substantially all of the cost of fuel.
Alabama Power and Georgia Power have contracts with the United States, acting through the DOE, that provide for the permanent disposal of spent nuclear fuel. The DOE failed to begin disposing of spent fuel in 1998, as required by the contracts, and Alabama Power and Georgia Power have pursued and are pursuing legal remedies against the government for breach of contract. See Note 3 to the financial statements of Southern Company, Alabama Power, and Georgia Power under "Nuclear Fuel Disposal Costs" in Item 8 herein for additional information.
Natural Gas
Recent advances in natural gas drilling in shale producing regions of the United States have resulted in historically high supplies of natural gas and relatively low prices for natural gas. Procurement plans for natural gas supply and transportation to serve regulated utility customers are reviewed and approved by the state regulatory agencies in which Southern Company Gas operates. Southern Company Gas purchases natural gas supplies in the open market by contracting with producers and marketers and from its wholly-owned subsidiary, Sequent Energy Management, L.P., under asset management agreements in states where such agreements are approved by the applicable state regulatory agency. Southern Company Gas also contracts for transportation and storage services from interstate pipelines that are regulated by the FERC. When firm pipeline services are temporarily not needed, Southern Company Gas may release the services in the secondary market under FERC-approved capacity release provisions or utilize asset management arrangements, thereby reducing the net cost of natural gas charged to customers for most of the natural gas distribution utilities. Peak-use requirements are met through utilization of company-owned storage facilities, pipeline transportation capacity, purchased storage services, peaking facilities, and other supply sources, arranged by either transportation customers or Southern Company Gas.
Territory Served by the Southern Company System
Traditional Electric Operating Companies and Southern Power
The territory in which the traditional electric operating companies provide retail electric service comprises most of the states of Alabama and Georgia, together with the northwestern portion of Florida and southeastern Mississippi. In this territory there are non-affiliated electric distribution systems that obtain some or all of their power requirements either directly or indirectly from the traditional electric operating companies. As of December 31, 2017, the territory had an area of approximately 120,000 square miles and an estimated population of approximately 17 million. Southern Power sells electricity at market-based rates in the wholesale market, primarily to investor-owned utilities, IPPs, municipalities, and other load-serving entities, as well as commercial and industrial customers.
Alabama Power is engaged, within the State of Alabama, in the generation, transmission, distribution, and purchase of electricity and the sale of electric service, at retail in approximately 400 cities and towns (including Anniston, Birmingham, Gadsden, Mobile, Montgomery, and Tuscaloosa), as well as in rural areas, and at wholesale to 14 municipally-owned electric distribution systems, 11 of which are served indirectly through sales to the Alabama Municipal Electric Authority, and two rural distributing cooperative associations. Alabama Power owns coal reserves near its Plant Gorgas and uses the output of coal from the reserves in its generating plants. Alabama Power also sells, and cooperates with dealers in promoting the sale of, electric appliances and products and markets and sells outdoor lighting services.

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

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

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

For information relating to KWH sales by customer classification for the traditional electric operating companies, see MANAGEMENT'S DISCUSSION AND ANALYSIS – RESULTS OF OPERATIONS of each traditional electric operating company in Item 7 herein. For information relating to the number of retail customers served by customer classification for the traditional electric operating companies, see SELECTED FINANCIAL DATA of each traditional electric operating company in Item 6 herein. Also, for information relating to the sources of revenues for Southern Company, each traditional electric operating company, and Southern Power, reference is made to Item 7 herein.

The RUS has authority to make loans to cooperative associations or corporations to enable them to provide electric service to customers in rural sections of the country. As of December 31, 2017, there were approximately 62 electric cooperative distribution systems operating in the territory in which the traditional electric operating companies provide electric service at retail or wholesale.

One of these organizations, PowerSouth, is a generating and transmitting cooperative selling power to several distributing cooperatives, municipal systems, and other customers in south Alabama and northwest Florida. As of December 31, 2017, PowerSouth owned generating units with approximately 2,100 MWs of nameplate capacity, including an undivided 8.16% ownership interest in Alabama Power's Plant Miller Units 1 and 2. PowerSouth's facilities were financed with RUS loans secured by long-term contracts requiring distributing cooperatives to take their requirements from PowerSouth to the extent such energy is available. See PROPERTIES – "Jointly-Owned Facilities" in Item 2 herein for details of Alabama Power's joint-ownership with PowerSouth of a portion of Plant Miller. Alabama Power has a system supply agreement with PowerSouth to provide 200 MWs of capacity service through December 31, 2030 with an option to extend and renegotiate in the event Alabama Power builds new generation or contracts for new capacity.

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

OPC is an EMC owned by its 38 retail electric distribution cooperatives, which provide retail electric service to customers in Georgia. OPC provides wholesale electric power to its members through its generation assets and power purchased from other suppliers.

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

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

As of December 31, 2017, there were approximately 72 municipally-owned electric distribution systems operating in the territory in which the traditional electric operating companies provide electric service at retail or wholesale.

As of December 31, 2017, 48 municipally-owned electric distribution systems and one county-owned system received their requirements through MEAG Power, which was established by a Georgia state statute in 1975. MEAG Power serves these requirements from self-owned generation facilities, some of which are jointly-owned with Georgia Power, and purchases from other resources. MEAG Power also has a pseudo scheduling and services agreement with Georgia Power. Dalton serves its requirements from self-owned generation facilities, some of which are jointly-owned with Georgia Power, and through purchases from Georgia Power and Southern Power through a service agreement.

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

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

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

Southern Company Gas

Southern Company Gas is engaged in the distribution of natural gas in seven states through the natural gas distribution utilities. The natural gas distribution utilities construct, manage, and maintain intrastate natural gas pipelines and distribution facilities. Details of the natural gas distribution utilities at December 31, 2017 are as follows:

| Utility | State | Number of customers (in thousands) | Approximate miles of pipe |
|---|---|---|---|
| Nicor Gas | Illinois | 2,228 | 34,300 |
| Atlanta Gas Light Company | Georgia | 1,622 | 33,500 |
| Virginia Natural Gas | Virginia | 299 | 5,600 |
| Elizabethtown Gas(*) | New Jersey | 292 | 3,200 |
| Florida City Gas | Florida | 109 | 3,700 |
| Chattanooga Gas Company | Tennessee | 66 | 1,600 |
| Elkton Gas(*) | Maryland | 7 | 100 |
| Total | | 4,623 | 82,000 |

(*) For information relating to the pending asset sales of Elizabethtown Gas and Elkton Gas, see MANAGEMENT'S DISCUSSION AND ANALYSIS – OVERVIEW – "Merger, Acquisition, and Disposition Activities" of Southern Company Gas in Item 7 herein and Note 11 to the financial statements of Southern Company Gas under "Proposed Sale of Elizabethtown Gas and Elkton Gas" in Item 8 herein.

For information relating to the sources of revenue for Southern Company Gas, see MANAGEMENT'S DISCUSSION AND ANALYSIS – RESULTS OF OPERATIONS and – FUTURE EARNINGS POTENTIAL of Southern Company Gas in Item 7 herein.

Competition

Electric

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

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

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

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

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

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

As of December 31, 2017, Alabama Power had cogeneration contracts in effect with eight industrial customers. Under the terms of these contracts, Alabama Power purchases excess energy generated by such companies. During 2017, Alabama Power purchased approximately 98 million KWHs from such companies at a cost of $3 million.

As of December 31, 2017, Georgia Power had contracts in effect with 27 small power producers whereby Georgia Power purchases their excess generation. During 2017, Georgia Power purchased 1.6 billion KWHs from such companies at a cost of $114 million. Georgia Power also has PPAs for electricity with four cogeneration facilities. Payments are subject to reductions for failure to meet minimum capacity output. During 2017, Georgia Power purchased 26 million KWHs at a cost of $0.7 million from these facilities.

Also during 2017, Georgia Power purchased energy from three customer-owned generating facilities. These customers provide only energy to Georgia Power, make no capacity commitment, and are not dispatched by Georgia Power. During 2017, Georgia Power purchased a total of 317 million KWHs from the three customers at a cost of approximately $25 million.

As of December 31, 2017, Gulf Power had agreements in effect with various industrial, commercial, and qualifying facilities pursuant to which Gulf Power purchases "as available" energy from customer-owned generation. During 2017, Gulf Power purchased 277 million KWHs from such companies for approximately $7 million.

As of December 31, 2017, Mississippi Power had a cogeneration agreement in effect with one of its industrial customers. Under the terms of this contract, Mississippi Power purchases any excess generation. During 2017, Mississippi Power did not purchase any excess generation from this customer.

Natural Gas

Southern Company Gas' natural gas distribution utilities do not compete with other distributors of natural gas in their exclusive franchise territories but face competition from other energy products. Their principal competitors are electric utilities and fuel oil and propane providers serving the residential, commercial, and industrial markets in their service areas for customers who are considering switching to or from a natural gas appliance.

Competition for heating as well as general household and small commercial energy needs generally occurs at the initial installation phase when the customer or builder makes decisions as to which types of equipment to install. Customers generally use the chosen energy source for the life of the equipment.

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

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

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

The availability and affordability of natural gas have provided cost advantages and further opportunity for growth of the businesses.

Seasonality

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

Regulation

State Commissions

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

Federal Power Act

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

Alabama Power and Georgia Power are also subject to the provisions of the Federal Power Act or the earlier Federal Water Power Act applicable to licensees with respect to their hydroelectric developments. As of December 31, 2017, among the hydroelectric projects subject to licensing by the FERC are 14 existing Alabama Power generating stations having an aggregate installed capacity of 1,670,000 KWs and 17 existing Georgia Power generating stations and one generating station partially owned by Georgia Power, with a combined aggregate installed capacity of 1,087,296 KWs.

In 2013, the FERC issued a new 30-year license to Alabama Power for Alabama Power's seven hydroelectric developments on the Coosa River (Weiss, Henry, Logan Martin, Lay, Mitchell, Jordan, and Bouldin). Alabama Power filed a petition requesting rehearing of the FERC order granting the relicense seeking revisions to several conditions of the license. Alabama Rivers Alliance, American Rivers, the Georgia Environmental Protection Division, and the Atlanta Regional Commission also filed petitions for rehearing of the FERC order. In April 2016, the FERC issued an order granting in part and denying in part Alabama Power's rehearing request. The order also denied all of the other rehearing requests. In May 2016, Alabama Rivers Alliance and American Rivers filed a second rehearing request and, in June 2016, also filed a petition with the U.S. Court of Appeals for the District of Columbia Circuit for review of the license and the rehearing denial order. The FERC issued an order in September 2016 denying the second rehearing request, and American Rivers and Alabama Rivers Alliance subsequently filed an appeal of that order at the U.S. Court of Appeals for the District of Columbia Circuit. The U.S. Court of Appeals for the District of Columbia Circuit consolidated the two appeals into one proceeding.

In 2017, Alabama Power continued the process of developing an application to relicense the Harris Dam project on the Tallapoosa River, which is expected to be filed with the FERC by November 30, 2021. The current Harris Dam project license will expire on November 30, 2023.

In 2017, Georgia Power continued the process of developing an application to relicense the Wallace Dam project on the Oconee River. The current Wallace Dam project license will expire on June 1, 2020. Georgia Power's hydro electric licenses expiring in 2023 include the Lloyd Shoals project, the Riverview project, and the Langdale project. The FERC relicensing proceedings for these three projects are expected to begin in 2018.

Georgia Power and OPC also have a license, expiring in 2027, for the Rocky Mountain Plant, a pure pumped storage facility of 847,800 KW capacity. See PROPERTIES – "Jointly-Owned Facilities" in Item 2 herein for additional information.

Licenses for all projects, excluding those discussed above, expire in the years 2023-2066 in the case of Alabama Power's projects and in the years 2035-2044 in the case of Georgia Power's projects.

Upon or after the expiration of each license, the U.S. Government, by act of Congress, may take over the project or the FERC may relicense the project either to the original licensee or to a new licensee. In the event of takeover or relicensing to another, the original licensee is to be compensated in accordance with the provisions of the Federal Power Act, such compensation to reflect the net investment of the licensee in the project, not in excess of the fair value of the property, plus reasonable damages to other property of the licensee resulting from the severance therefrom of the property. The FERC may grant relicenses subject to certain requirements that could result in additional costs.

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

Nuclear Regulation

Alabama Power, Georgia Power, and Southern Nuclear are subject to regulation by the NRC. The NRC is responsible for licensing and regulating nuclear facilities and materials and for conducting research in support of the licensing and regulatory process, as mandated by the Atomic Energy Act of 1954, as amended; the Energy Reorganization Act of 1974, as amended; and the Nuclear Nonproliferation Act of 1978, as amended; and in accordance with the National Environmental Policy Act of 1969, as amended, and other applicable statutes. These responsibilities also include protecting public health and safety, protecting the environment, protecting and safeguarding nuclear materials and nuclear power plants in the interest of national security, and assuring conformity with antitrust laws.

The NRC licenses for Georgia Power's Plant Hatch Units 1 and 2 expire in 2034 and 2038, respectively. The NRC licenses for Alabama Power's Plant Farley Units 1 and 2 expire in 2037 and 2041, respectively. The NRC licenses for Plant Vogtle Units 1 and 2 expire in 2047 and 2049, respectively.

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

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

Environmental Laws and Regulations

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. Compliance with these existing environmental requirements involves significant capital and operating costs, a major portion of which is expected to be recovered through existing ratemaking provisions or through market-based contracts. There is no assurance, however, that all such costs will be recovered. For Southern Company Gas, substantially all of these costs are related to former manufactured gas plants sites, which are primarily recovered through existing ratemaking provisions. See Note 3 to the financial statements of Southern Company Gas under "Environmental Matters" in Item 8 herein for additional information.

Compliance with federal environmental laws and resulting regulations has been, and will continue to be, a significant focus for Southern Company, each traditional electric operating company, Southern Power, SEGCO, and Southern Company Gas. 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. See MANAGEMENT'S DISCUSSION AND ANALYSIS – FUTURE EARNINGS POTENTIAL – "Environmental Matters" of Southern Company and each of the traditional electric operating companies in Item 7 herein for additional information about environmental issues, including, but not limited to, proposed and final regulations related to air quality, water quality, CCRs, and global climate issues. See MANAGEMENT'S DISCUSSION AND ANALYSIS – FUTURE EARNINGS POTENTIAL – "Environmental Matters" of Southern Power in Item 7 herein for additional information about environmental issues and global climate issues. See MANAGEMENT'S DISCUSSION AND ANALYSIS – FUTURE EARNINGS POTENTIAL – "Environmental Matters" of Southern Company Gas in Item 7 herein for additional information about environmental remediation liabilities.

The Southern Company system's ultimate environmental compliance strategy, including potential electric generating unit retirement and replacement decisions, and future environmental capital expenditures will depend on various factors, such as state-level adoption and implementation of requirements, the availability and cost of any deployed control technology, and the outcome of pending and/or future legal challenges. 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. Environmental compliance spending over the next several years may differ materially from the amounts estimated. Such expenditures could affect results of operations, cash flows, and financial condition if such costs are not recovered on a timely basis through regulated rates for the traditional electric operating companies and the natural gas distribution utilities or through long-term wholesale agreements for the traditional electric operating companies and Southern Power. Further, higher costs that are recovered through regulated rates could contribute to reduced demand for energy, which could negatively affect results of operations, cash flows, and financial condition. Additionally, many commercial and industrial customers may also be affected by existing and future environmental requirements, which for some may have the potential to ultimately affect their demand for electricity and natural gas. See "Construction Program" herein and MANAGEMENT'S DISCUSSION AND ANALYSIS – FUTURE EARNINGS POTENTIAL – "Environmental Matters" of Southern Company, each of the traditional electric operating companies, Southern Power, and Southern Company Gas in Item 7 herein for additional information. The ultimate outcome of these matters cannot be determined at this time.

Rate Matters

Rate Structure and Cost Recovery Plans

Electric

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

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

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

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

See Note 3 to the financial statements of Southern Company and Mississippi Power under "Kemper County Energy Facility" in Item 8 herein and MANAGEMENT'S DISCUSSION AND ANALYSIS – FUTURE EARNINGS POTENTIAL – "Kemper County Energy Facility – Rate Recovery" of Mississippi Power in Item 7 herein for information on cost recovery plans with respect to the Kemper County energy facility.

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

Mississippi Power serves long-term contracts with rural electric cooperative associations and a municipality located in southeastern Mississippi under cost-based electric tariffs which are subject to regulation by the FERC. The contracts with these wholesale customers represented 19.3% of Mississippi Power's operating revenues in 2017 and are largely subject to rolling 10-

year cancellation notices. Historically, these wholesale customers have acted as a group and any changes in contractual relationships for one customer are likely to be followed by the other wholesale customers.

Natural Gas

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

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

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

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

Integrated Resource Planning

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

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

Georgia Power

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

See Note 3 to the financial statements of Southern Company under "Regulatory Matters – Georgia Power – Rate Plans" and " – Integrated Resource Plan" and "Nuclear Construction" and Note 3 to the financial statements of Georgia Power under "Retail Regulatory Matters – Rate Plans," "– Integrated Resource Plan," and "– Nuclear Construction" in Item 8 herein for additional information.

Gulf Power

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

Florida law, any 10-year site plans submitted by an electric utility are considered tentative information for planning purposes only and may be amended at any time at the discretion of the utility with written notification to the Florida PSC.

Gulf Power's most recent 10-year site plan was classified by the Florida PSC as "suitable" in November 2017. The plan identifies environmental regulations and potential legislation or regulation that would impose mandatory restrictions on greenhouse gas emissions. See MANAGEMENT'S DISCUSSION AND ANALYSIS – FUTURE EARNINGS POTENTIAL – "Environmental Matters – Environmental Laws and Regulations – Air Quality," "– Environmental Laws and Regulations – Coal Combustion Residuals," and "– Global Climate Issues" of Gulf Power in Item 7 herein.

As a result of the cost to comply with environmental regulations imposed by the EPA, Gulf Power retired its coal-fired generation at Plant Smith Units 1 and 2 (357 MWs) in March 2016. In August 2016, the Florida PSC approved Gulf Power's request to reclassify the remaining net book value of Plant Smith Units 1 and 2 and the remaining materials and supplies associated with these units as of the retirement date, totaling approximately $63 million, to a regulatory asset. Gulf Power began amortizing the investment balances over 15 years effective January 1, 2018 as determined in a rate case settlement agreement approved by the Florida PSC on April 4, 2017.

Mississippi Power

Mississippi Power's 2010 IRP indicated that, among other things, Mississippi Power planned to construct the Kemper County energy facility as an IGCC to meet its identified needs, to add environmental controls at Plant Daniel Units 1 and 2, to defer environmental controls at Plant Watson Units 4 and 5, and to continue operation of the combined cycle Plant Daniel Units 3 and 4. See MANAGEMENT'S DISCUSSION AND ANALYSIS – FUTURE EARNINGS POTENTIAL – "Environmental Matters – Environmental Laws and Regulations – Air Quality" and "– Global Climate Issues" of Mississippi Power in Item 7 herein.

On February 6, 2018, the Mississippi PSC approved a settlement agreement related to cost recovery for the Kemper County energy facility, pursuant to which Mississippi Power agreed to file a Reserve Margin Plan (RMP) by August 2018. The RMP will include many of the same aspects of a traditional IRP, but the RMP will also contain alternatives proposed by Mississippi Power to address its current capacity which is in excess of Mississippi Power's long-term targeted reserve margin. The ultimate outcome of this matter cannot be determined at this time.

For additional information regarding the Kemper County energy facility, see MANAGEMENT'S DISCUSSION AND ANALYSIS – FUTURE EARNINGS POTENTIAL – "Kemper County Energy Facility" of Mississippi Power in Item 7 herein and Note 3 to the financial statements of Southern Company and Mississippi Power under "Kemper County Energy Facility" in Item 8 herein.

Employee Relations

The Southern Company system had a total of 31,344 employees on its payroll at December 31, 2017.

| | Employees at December 31, 2017 |
|---|---|
| Alabama Power | 6,613 |
| Georgia Power | 6,986 |
| Gulf Power | 1,288 |
| Mississippi Power | 1,242 |
| PowerSecure | 1,448 |
| SCS | 3,740 |
| Southern Company Gas | 5,318 |
| Southern Nuclear | 3,936 |
| Southern Power | 541 |
| Other | 232 |
| Total | 31,344 |

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

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

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

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

Mississippi Power has an agreement with the IBEW covering wages and working conditions, which is in effect through May 1, 2019. In 2015, Mississippi Power signed a separate agreement with the IBEW related solely to the Kemper County energy facility; that current agreement is in effect through March 15, 2021. In August 2017, Mississippi Power signed an agreement with the IBEW that added several job classifications and provided guidelines related to the reorganization at the Kemper County energy facility.

Southern Nuclear has a five-year agreement with the IBEW covering certain employees at Plants Hatch and Plant Vogtle Units 1 and 2, which is in effect through June 30, 2021. A five-year agreement between Southern Nuclear and the IBEW representing certain employees at Plant Farley is in effect through August 15, 2019. Upon notice given at least 60 days prior to that date, negotiations may be initiated with respect to agreement terms to be effective after such date.

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

The natural gas distribution utilities have separate agreements with local unions of the IBEW and Utilities Workers Union of America covering wages, working conditions, and procedures for handling grievances and arbitration. Nicor Gas' agreement with the IBEW is effective through February 29, 2020. Virginia Natural Gas' agreement with the IBEW is effective through May 16, 2020. Elizabethtown Gas' agreement with the Utility Workers Union of America is effective through November 21, 2019. The agreements also make the terms of the Southern Company Gas pension plan subject to collective bargaining with the unions when significant changes to the benefit accruals are considered by Southern Company Gas.

Effective in December 2017, 538 employees transferred from SCS to Southern Power. Southern Power became obligated for related employee costs including pension, other postretirement benefits, and stock-based compensation and has recognized the respective balance sheet assets and liabilities, including accumulated other comprehensive income impacts, in its balance sheet at December 31, 2017. Prior to the transfer of employees, Southern Power's agreements with SCS provided for employee services rendered at amounts in compliance with FERC regulations.

## Item 1A. RISK FACTORS

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

### UTILITY REGULATORY, LEGISLATIVE, AND LITIGATION RISKS

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

Southern Company and its subsidiaries, including the traditional electric operating companies, Southern Power, and Southern Company Gas, are subject to substantial regulation from federal, state, and local regulatory agencies. Southern Company and its subsidiaries are required to comply with numerous laws and regulations and to obtain numerous permits, approvals, and certificates from the governmental agencies that regulate various aspects of their businesses. Jointly-owned facilities may be subject to regulation by governmental agencies of more than one state and those state's governmental agencies may have different policies with respect to such jointly-owned facilities. The traditional electric operating companies and the natural gas distribution utilities seek to recover their costs (including a reasonable return on invested capital) through their retail rates, which must be approved by the applicable state PSC or other applicable state regulatory agency. A state PSC or other applicable state regulatory agency, in a future rate proceeding, may alter the timing or amount of certain costs for which recovery is allowed or modify the current authorized rate of return. Rate refunds may also be required. Additionally, the rates charged to wholesale customers by the traditional electric operating companies and by Southern Power and the rates charged to natural gas transportation customers by Southern Company Gas' pipeline investments must be approved by the FERC. These wholesale rates could be affected by changes to Southern Power's and the traditional electric operating companies' ability to conduct business pursuant to FERC market-based rate authority. The FERC rules related to retaining the authority to sell electricity at market-based rates in the wholesale markets are important for the traditional electric operating companies and Southern Power if they are to remain competitive in the wholesale markets in which they operate.

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

The Southern Company system's costs of compliance with environmental laws are significant. The costs of compliance with current and future environmental laws and the incurrence of environmental liabilities could negatively impact the net income, cash flows, and financial condition of the registrants.

The Southern Company system's operations are subject to extensive regulation by state and federal environmental agencies through a variety of laws and regulations governing air, water, land, and the protection of other natural resources. Compliance with these existing environmental requirements involves significant capital and operating costs, a major portion of which is expected to be recovered through existing ratemaking provisions or through market-based contracts. There is no assurance, however, that all such costs will be recovered. The registrants expect that these expenditures will continue to be significant in the future.

The EPA has adopted and is implementing regulations governing air and water quality, including the emission of nitrogen oxide, sulfur dioxide, fine particulate matter, ozone, mercury, and other air pollutants under the Clean Air Act and regulations governing cooling water intake structures and effluent guidelines for steam electric generating plants under the Clean Water Act. The EPA also is reconsidering regulations governing the disposal of CCR, including coal ash and gypsum, in landfills and surface impoundments at power generation plants.

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

Existing environmental laws and regulations may be revised or new laws and regulations related to air, water, land, and the protection of other natural resources may be adopted or become applicable to the traditional electric operating companies, Southern Power, and/or Southern Company Gas.

Litigation over environmental issues and claims of various types, including property damage, personal injury, common law nuisance, and citizen enforcement of environmental requirements such as 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, releases of regulated substances, and alleged exposure to regulated substances, and/or requests for injunctive relief in connection with such matters.

The Southern Company system's ultimate environmental compliance strategy, including potential electric generating unit retirement and replacement decisions, and future environmental capital expenditures 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. 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. Environmental compliance spending over the next several years may differ materially from the amounts estimated. Such expenditures could affect results of operations, cash flows, and financial condition if such costs are not recovered on a timely basis through regulated rates for the traditional electric operating companies and the natural gas distribution utilities or through long-term wholesale agreements for the traditional electric operating companies and Southern Power. Further, higher costs that are recovered through regulated rates could contribute to reduced demand for energy, which could negatively affect results of operations, cash flows, and financial condition. 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 or natural gas.

Compliance with any new or revised environmental laws or regulations could affect many areas of the traditional electric operating companies', Southern Power's, and the natural gas distribution utilities' operations. The ultimate impact 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. Additionally, many commercial and industrial customers may also be affected by existing and future environmental requirements, which may affect their demand for electricity and natural gas.

The Southern Company system may be exposed to regulatory and financial risks related to the impact of greenhouse gas (GHG) legislation and regulation.

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 the 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 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.

Costs associated with these actions could be significant to the utility industry and the Southern Company system. However, the ultimate impact of these environmental laws and regulations 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.

Because natural gas is a fossil fuel with lower carbon content relative to other fossil fuels, future GHG constraints may create additional demand for natural gas, both for production of electricity and direct use in homes and businesses. The impact is already being seen in the power production sector due to both environmental regulations and low natural gas costs. Future GHG constraints focused on minimizing emissions from natural gas, albeit lower than other fossil fuels, could likewise result in increased costs to the Southern Company system and affect the demand for natural gas as well as the prices charged to customers and the competitive position of natural gas.

The net income of Southern Company, the traditional electric operating companies, and Southern Power could be negatively impacted by changes in regulations related to transmission planning processes and competition in the wholesale electric markets.

The traditional electric operating companies currently own and operate transmission facilities as part of a vertically integrated utility. A small percentage of transmission revenues are collected through the wholesale electric tariff but the majority of transmission revenues are collected through retail rates. FERC rules pertaining to regional transmission planning and cost allocation present challenges to transmission planning and the wholesale market structure in the Southeast. The key impacts of these rules include:

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

The FERC rules related to transmission are intended to spur the development of new transmission infrastructure to promote and encourage the integration of renewable sources of supply as well as facilitate competition in the wholesale market by providing more choices to wholesale power customers. Technology changes in the power and fuel industries continue to create significant impacts to wholesale transaction cost structures. The impact of these and other such developments and the effect of changes in levels of wholesale supply and demand are uncertain. The financial condition, net income, and cash flows of Southern Company, the traditional electric operating companies, and Southern Power could be adversely affected by these and other changes.

The traditional electric operating companies and Southern Power could be subject to higher costs as a result of implementing and maintaining compliance with the North American Electric Reliability Corporation mandatory reliability standards along with possible associated penalties for non-compliance.

Owners and operators of bulk power systems, including the traditional electric operating companies, are subject to mandatory reliability standards enacted by the North American Electric Reliability Corporation and enforced by the FERC. Compliance with or changes in the mandatory reliability standards may subject the traditional electric operating companies and Southern Power to higher operating costs and/or increased capital expenditures. If any traditional electric operating company or Southern Power is found to be in noncompliance with these standards, such traditional electric operating company or Southern Power could be subject to sanctions, including substantial monetary penalties.

Southern Company and its subsidiaries are continuing to review the Tax Reform Legislation, which has and could have a further material impact on the results of operations, financial condition, and cash flows of the registrants.

On December 22, 2017, the Tax Reform Legislation was signed into law and became effective on January 1, 2018. The Tax Reform Legislation significantly changes the U.S. Internal Revenue Code by, among other things, reducing the federal corporate income tax rate to 21% and repealing the corporate alternative minimum tax. As a result of the tax rate reduction, Southern Company recorded net, non-cash federal income tax benefits of $264 million in the fourth quarter 2017, comprised primarily of a $743 million tax benefit resulting from reductions in deferred tax liabilities at Southern Power, partially offset by tax expenses of $372 million and $93 million resulting from reductions in deferred tax assets at Mississippi Power and Southern Company Gas, respectively.

The tax rate reduction also resulted in a $6.9 billion increase in regulatory liabilities and a $0.4 billion decrease in regulatory assets across the traditional electric operating companies and the natural gas distribution utilities. The regulatory treatment of certain impacts of the Tax Reform Legislation is subject to the discretion of the FERC and the relevant state regulatory bodies.

For businesses other than regulated utility businesses, the Tax Reform Legislation allows 100% bonus depreciation of qualified property through 2022, which phases down through 2027, and limits interest expense deductions. 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. The Tax Reform Legislation retains normalization provisions for public utility property and existing renewable energy incentives. However, the tax rate reduction delays the utilization of renewable tax credit carryforwards as described in Note 5 to the financial statements of Southern Company, Alabama Power, Georgia Power, and Southern Power under "Federal Tax Reform Legislation" in Item 8 herein.

The Tax Reform Legislation also includes provisions that limit the utilization of future net operating losses and limit the deductibility of certain executive compensation and other expenses. Further, 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 funds from operations to debt percentage, used by the credit rating agencies to assess the registrants, Southern Company Gas Capital, and Nicor Gas may be negatively impacted.

The Tax Reform Legislation is unclear in certain respects and will require interpretations, guidance, and implementing regulations by 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. Southern Company and its subsidiaries are continuing to review the Tax Reform Legislation and are assessing whether any potential actions are available to mitigate adverse impacts of the legislation. Southern Company and its subsidiaries may identify additional impacts as they further assess the Tax Reform Legislation and as the IRS issues interpretations and implements regulations. Southern Company will continue to monitor the actions of state legislatures and state taxing authorities to see how the states may adopt and implement the Tax Reform Legislation. While the ultimate impact of the Tax Reform Legislation, future interpretations and implementation of regulations by the IRS and state tax authorities, and any mitigating actions Southern Company and its subsidiaries may take cannot be determined at this time, the Tax Reform Legislation had and could have a further material impact on the results of operations, financial condition and cash flows of the registrants.

OPERATIONAL RISKS

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

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

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

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

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

Alabama Power owns, and contracts for the operation of, two nuclear units and Georgia Power holds undivided interests in, and contracts for the operation of, four existing nuclear units. The six existing units are operated by Southern Nuclear and represent approximately 3,680 MWs, or 8% of the Southern Company system's electric generation capacity as of December 31, 2017. In addition, these units generated approximately 25% of the total KWHs generated by each of Alabama Power and Georgia Power in the year ended December 31, 2017. In addition, Southern Nuclear, on behalf of Georgia Power and the other Vogtle Owners, is managing the construction of Plant Vogtle Units 3 and 4. Due solely to the increase in nuclear generating capacity, the below risks are expected to increase incrementally once Plant Vogtle Units 3 and 4 are operational. Nuclear facilities are subject to environmental, safety, health, operational, and financial risks such as:

- the potential harmful effects on the environment and human health and safety resulting from a release of radioactive materials in connection with the operation of nuclear facilities and the storage, handling, and disposal of radioactive material, including spent nuclear fuel;
- uncertainties with respect to the ability to dispose of spent nuclear fuel and the need for longer term on-site storage;
- uncertainties with respect to the technological and financial aspects of decommissioning nuclear plants at the end of licensed lives and the ability to maintain and anticipate adequate capital reserves for decommissioning;

- limitations on the amounts and types of insurance commercially available to cover losses that might arise in connection with the nuclear operations of Alabama Power and Georgia Power or those of other commercial nuclear facility owners in the U.S.;
- potential liabilities arising out of the operation of these facilities;
- significant capital expenditures relating to maintenance, operation, security, and repair of these facilities, including repairs and upgrades required by the NRC;
- the threat of a possible terrorist attack, including a potential cyber security attack; and
- the potential impact of an accident or natural disaster.

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

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

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

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

Southern Company Gas' natural gas distribution and storage activities involve a variety of inherent hazards and operating risks, such as leaks, accidents, explosions, and mechanical problems, which could result in serious injury to employees and non-employees, loss of human life, significant damage to property, environmental pollution, and impairment of its operations. The location of pipelines and storage facilities near populated areas could increase the level of damage resulting from these risks. Additionally, these pipeline and storage facilities are subject to various state and other regulatory requirements. Failure to comply with these regulatory requirements could result in substantial monetary penalties or potential early retirement of storage facilities, which could trigger an associated impairment. The occurrence of any of these events not fully covered by insurance or otherwise could adversely affect Southern Company Gas' and Southern Company's financial condition and results of operations.

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

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

Despite the implementation of robust security measures, all assets are potentially vulnerable to disability, failures, or unauthorized access due to human error, natural disasters, technological failure, or internal or external physical attacks. If assets were to fail, be physically damaged, or be breached and were not recovered in a timely way, the traditional electric operating companies, Southern Power, or Southern Company Gas, as applicable, may be unable to fulfill critical business functions. Moreover, the amount and scope of insurance maintained against losses resulting from any such events or physical security breaches may not be sufficient to cover losses or otherwise adequately compensate for any disruptions to business that could result.

These events could harm the reputation of and negatively affect the financial results of the registrants through lost revenues and costs to repair damage, if such costs cannot be recovered.

An information security incident, including a cybersecurity breach, or the failure of one or more key information technology systems, networks, or processes could impact the ability of the registrants to operate and could adversely affect financial results and liquidity.

Information security risks have generally increased in recent years as a result of the proliferation of new technology and increased sophistication and frequency of cyber attacks and data security breaches. The traditional electric operating companies, Southern Power, and Southern Company Gas operate in highly regulated industries that require the continued operation of sophisticated information technology systems and network infrastructure, which are part of interconnected distribution systems. Because of the critical nature of the infrastructure, increased connectivity to the internet, and technology systems' inherent vulnerability to disability or failures due to hacking, viruses, acts of war or terrorism, or other types of data security breaches, Southern Company and its subsidiaries face a heightened risk of cyberattack. Parties that wish to disrupt the U.S. bulk power system or Southern Company system operations could view these computer systems, software, or networks as targets. The registrants and their third-party vendors have been subject, and will likely continue to be subject, to attempts to gain unauthorized access to their information technology systems and confidential data or to attempts to disrupt utility operations. As a result, Southern Company and its subsidiaries face on-going threats to their assets, including assets deemed critical infrastructure, where databases and systems have been, and will likely continue to be, subject to advanced computer viruses or other malicious codes, unauthorized access attempts, phishing, and other cyber attacks. While there has been no material impact on business or operations from these attacks, the registrants cannot guarantee that security efforts will prevent breaches, operational incidents, or other breakdowns of information technology systems and network infrastructure.

In addition, in the ordinary course of business, Southern Company and its subsidiaries collect and retain sensitive information, including personally identifiable information about customers, employees, and stockholders, and other confidential information. In some cases, administration of certain functions may be outsourced to third party service providers that could also be targets of cyber attacks. Generally, Southern Company and its subsidiaries enter certain contractual security guarantees and assurances with these third parties to help ensure the security and safety of this information.

Despite the implementation of robust security measures, all assets are potentially vulnerable to disability, failures, or unauthorized access due to human error, natural disasters, technological failure, or internal or external cyber attacks. If assets were to fail or be breached and were not recovered in a timely way, the affected registrant may be unable to fulfill critical business functions, and sensitive and other data could be compromised. Any cyber breach or theft, damage, or improper disclosure of sensitive electronic data may also subject the affected registrant to penalties and claims from regulators or other third parties. Moreover, the amount and scope of insurance maintained against losses resulting from any such events or security breaches may not be sufficient to cover losses or otherwise adequately compensate for any disruptions to business that could result.

These events could negatively affect the financial results of the registrants through lost revenues, costs to recover and repair damage, and costs associated with governmental actions in response to such attacks, litigation, and reputational damage if such costs cannot be recovered through insurance or otherwise.

The Southern Company system may not be able to obtain adequate natural gas and other fuel supplies required to operate the traditional electric operating companies' and Southern Power's electric generating plants or serve Southern Company Gas' natural gas customers.

The traditional electric operating companies and Southern Power purchase fuel, including coal, natural gas, uranium, fuel oil, and biomass, as applicable, from a number of suppliers. Disruption in the delivery of fuel, including disruptions as a result of, among other things, transportation delays, weather, labor relations, force majeure events, or environmental regulations affecting any of these fuel suppliers, could limit the ability of the traditional electric operating companies and Southern Power to operate certain facilities, which could result in higher fuel and operating costs and potentially reduce the net income of the affected traditional electric operating company or Southern Power and Southern Company.

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

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

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

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

Most of Southern Power's generating capacity has been sold to purchasers under PPAs. Southern Power's top three customers, Georgia Power, Duke Energy Corporation, and Morgan Stanley Capital Group accounted for 11.3%, 6.7%, and 4.5%, respectively, of Southern Power's total revenues for the year ended December 31, 2017. In addition, the traditional electric operating companies enter into PPAs with non-affiliated parties. Revenues are dependent on the continued performance by the purchasers of their obligations under these PPAs. The failure of one of the purchasers to perform its obligations could have a negative impact on the net income and cash flows of the affected traditional electric operating company or Southern Power and of Southern Company. Although the credit evaluations undertaken and contractual protections implemented by Southern Power and the traditional electric operating companies take into account the possibility of default by a purchaser, actual exposure to a default by a purchaser may be greater than predicted or specified in the applicable contract.

Additionally, neither Southern Power nor any traditional electric operating company can predict whether the PPAs will be renewed at the end of their respective terms or on what terms any renewals may be made. The failure of the traditional electric operating companies or Southern Power to satisfy minimum operational or availability requirements under these PPAs could result in payment of damages or termination of the PPAs.

The asset management arrangements between Southern Company Gas' wholesale gas services and its customers, including the natural gas distribution utilities, may not be renewed or may be renewed at lower levels, which could have a significant impact on Southern Company Gas' financial results.

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

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

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

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

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

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

Southern Company Gas' gas marketing services is affected by competition from other energy marketers providing similar services in Southern Company Gas' service territories, most notably in Illinois and Georgia. Southern Company Gas' wholesale gas services competes for sales with national and regional full-service energy providers, energy merchants and producers, and pipelines based on the ability to aggregate competitively-priced commodities with transportation and storage capacity. Southern Company Gas competes with natural gas facilities in the Gulf Coast region of the U.S., as the majority of the existing and proposed high deliverability salt-dome natural gas storage facilities in North America are located in the Gulf Coast region.

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

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

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

CONSTRUCTION RISKS

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

General

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

- shortages and inconsistent quality of equipment, materials, and labor;
- changes in labor costs and productivity;
- work stoppages;
- contractor or supplier delay or non-performance under construction, operating, or other agreements or non-performance by other major participants in construction projects;
- delays in or failure to receive necessary permits, approvals, tax credits, and other regulatory authorizations;
- delays associated with start-up activities, including major equipment failure and system integration, and/or operational performance (including additional costs to satisfy any operational parameters ultimately adopted by any PSC or other applicable state regulatory agency);

- operational readiness, including specialized operator training and required site safety programs;
- impacts of new and existing laws and regulations, including environmental laws and regulations;
- the outcome of legal challenges to projects, including legal challenges to regulatory approvals;
- failure to construct in accordance with permitting and licensing requirements;
- failure to satisfy any environmental performance standards and the requirements of tax credits and other incentives;
- continued public and policymaker support for such projects;
- adverse weather conditions or natural disasters;
- other unforeseen engineering or design problems;
- changes in project design or scope;
- environmental and geological conditions;
- delays or increased costs to interconnect facilities to transmission grids; and
- unanticipated cost increases, including materials and labor, and increased financing costs as a result of changes in market interest rates or as a result of construction schedule delays.

If a traditional electric operating company, Southern Power, or Southern Company Gas is unable to complete the development or construction of a project or decides to delay or cancel construction of a project, it may not be able to recover its investment in that project and may incur substantial cancellation payments under equipment purchase orders or construction contracts. Additionally, each Southern Company Gas pipeline construction project involves separate joint venture participants, Southern Power participates in partnership agreements with respect to renewable energy projects, and Georgia Power jointly owns Plant Vogtle Units 3 and 4 with other co-owners. Any failure by a partner or co-owner to perform its obligations under the applicable agreements could have a material negative impact on the applicable project under construction. In addition, partnership and joint ownership agreements may provide partners or co-owners with certain decision-making authority in connection with projects under construction.

Even if a construction project (including a joint venture construction project) is completed, the total costs may be higher than estimated and may not be recoverable through regulated rates, if applicable. In addition, construction delays and contractor performance shortfalls can result in the loss of revenues and may, in turn, adversely affect the net income and financial position of the affected registrant.

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

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

The largest construction project currently underway in the Southern Company system is Plant Vogtle Units 3 and 4.

Plant Vogtle Units 3 and 4 construction and rate recovery

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 a substantially fixed price engineering, procurement, and construction agreement, pursuant to which the EPC Contractor agreed to design, engineer, procure, construct, and test Plant Vogtle Units 3 and 4. 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 an agreement with the EPC Contractor to allow construction to continue (Interim Assessment Agreement). The Interim Assessment Agreement expired on July 27, 2017 upon the effectiveness of a services agreement between the Vogtle Owners and the EPC Contractor 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 (Vogtle Services Agreement). In August 2017, following completion of comprehensive cost to complete and cancellation cost assessments, Georgia Power filed its seventeenth Vogtle Construction Monitoring (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 Power Corporation (Bechtel) serving as the primary construction contractor. Facility design and engineering remains the responsibility of the EPC Contractor under the Vogtle Services Agreement. The construction completion agreement between Georgia Power, for itself and as agent for the other Vogtle Owners, and Bechtel (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.
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 Corporation; (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.
On December 21, 2017, the Georgia PSC voted to approve (and issued its related order on January 11, 2018) Georgia Power's recommendation to continue construction and 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 December 31, 2015 agreement between Westinghouse and the Vogtle Owners resolving disputes between the Vogtle Owners and the EPC Contractor under the original engineering, procurement, and construction agreement for Plant Vogtle Units 3 and 4 (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 the Customer Refunds, each as defined below) 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 return on equity (ROE) used to calculate the Nuclear Construction Cost Recovery (NCCR) tariff (a) from 10.95% (the ROE rate setting point authorized by the Georgia PSC in the 2013 Alternative Rate Plan) 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 allowance for funds used during construction 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 settlement agreement approved by the Georgia PSC on December 20, 2016. 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. 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 and Georgia Power's results of operations, financial condition, and liquidity.
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 Toshiba's guarantee of certain obligations of the EPC Contractor (Guarantee Settlement Agreement) and certain refunds to customers ordered by the Georgia PSC (Customer Refunds)). Georgia Power's construction work in progress 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.

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.

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

Southern Company Gas' significant investments in pipelines and pipeline development projects involve financial and execution risks.

Southern Company Gas has made significant investments in existing pipelines and pipeline development projects. Many of the existing pipelines are, and when completed many of the pipeline development projects will be, operated by third parties. If one of these agents fails to perform in a proper manner, the value of the investment could decline and Southern Company Gas could lose part or all of the investment. In addition, from time to time, Southern Company Gas may be required to contribute additional capital to a pipeline joint venture or guarantee the obligations of such joint venture.

With respect to certain pipeline development projects, Southern Company Gas will rely on its joint venture partners for construction management and will not exercise direct control over the process. All of the pipeline development projects are dependent on contractors for the successful and timely completion of the projects. Further, the development of pipeline projects involves numerous regulatory, environmental, construction, safety, political, and legal uncertainties and may require the expenditure of significant amounts of capital. These projects may not be completed on schedule, at the budgeted cost, or at all. There may be cost overruns and construction difficulties that cause Southern Company Gas' capital expenditures to exceed its initial expectations. Moreover, Southern Company Gas' revenues will not increase immediately upon the expenditure of funds on a pipeline project. Pipeline construction occurs over an extended period of time and Southern Company Gas will not receive material increases in revenues until the project is placed in service.

The occurrence of any of the foregoing events could adversely affect the results of operations, cash flows, and financial condition of Southern Company Gas and Southern Company.

FINANCIAL, ECONOMIC, AND MARKET RISKS

The electric generation and energy marketing operations of the traditional electric operating companies and Southern Power and the natural gas operations of Southern Company Gas are subject to risks, many of which are beyond their control, including changes in energy prices and fuel costs, which may reduce revenues and increase costs.

The generation, energy marketing, and natural gas operations of the Southern Company system are subject to changes in energy prices and fuel costs, which could increase the cost of producing power, decrease the amount received from the sale of energy, and/or make electric generating facilities less competitive. The market prices for these commodities may fluctuate significantly over relatively short periods of time. Among the factors that could influence energy prices and fuel costs are:

- prevailing market prices for coal, natural gas, uranium, fuel oil, biomass, and other fuels, as applicable, used in the generation facilities of the traditional electric operating companies and Southern Power and, in the case of natural gas,

distributed by Southern Company Gas, including associated transportation costs, and supplies of such commodities;
- demand for energy and the extent of additional supplies of energy available from current or new competitors;
- liquidity in the general wholesale electricity and natural gas markets;
- weather conditions impacting demand for electricity and natural gas;
- seasonality;
- transmission or transportation constraints, disruptions, or inefficiencies;
- availability of competitively priced alternative energy sources;
- forced or unscheduled plant outages for the Southern Company system, its competitors, or third party providers;
- the financial condition of market participants;

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

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

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

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

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

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

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

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

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

The operating results of the registrants are affected by weather conditions and may fluctuate on a seasonal and quarterly basis. In addition, catastrophic events, such as fires, earthquakes, hurricanes, tornadoes, floods, droughts, and storms, could result in substantial damage to or limit the operation of the properties of the traditional electric operating companies, Southern Power, and/or Southern Company Gas and could negatively impact results of operation, financial condition, and liquidity.

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

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

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

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

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

Southern Company and its subsidiaries have made significant acquisitions and investments in the past and may in the future make additional acquisitions, dispositions, or other strategic ventures or investments, including the proposed sale by Pivotal Utility Holdings, a wholly-owned subsidiary of Southern Company Gas, of the assets of its natural gas distribution utilities, Elizabethtown Gas and Elkton Gas, and the potential sale by Southern Power of a 33% equity interest in a newly-formed holding company that owns substantially all of Southern Power's solar assets. Southern Company and its subsidiaries continually seek opportunities to create value through various transactions, including acquisitions or sales of assets. Specifically, Southern Power continually seeks opportunities to execute its strategy 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, and other load-serving entities, as well as commercial and industrial customers.

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

These transactions also involve risks, including:

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

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

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

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

A downgrade in the credit ratings of any of the registrants, Southern Company Gas Capital, or Nicor Gas could negatively affect their ability to access capital at reasonable costs and/or could require posting of collateral or replacing certain indebtedness.

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

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

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

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

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

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

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

As of December 31, 2017, Mississippi Power's current liabilities exceeded current assets by approximately $911 million primarily due to a $900 million unsecured term loan that matures on March 31, 2018. Mississippi Power expects to refinance the unsecured term loan with external security issuances and/or borrowings from financial institutions or Southern Company. Mississippi Power has been informed by Southern Company that in the event sufficient funds are not available from external sources, Southern Company intends to provide Mississippi Power with loans and/or equity to fund the remaining indebtedness to mature and other cash needs over the next 12 months.

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

Failure to comply with debt covenants or conditions could adversely affect the ability of the registrants, Southern Company Gas Capital, or Nicor Gas to execute future borrowings.

The debt and credit agreements of the registrants, Southern Company Gas Capital, and Nicor Gas contain various financial and other covenants. Georgia Power's loan guarantee agreement with the DOE contains additional covenants, events of default, and mandatory prepayment events relating to the construction of Plant Vogtle Units 3 and 4. Failure to meet those covenants beyond applicable grace periods could result in accelerated due dates and/or termination of the agreements, which would negatively affect the applicable company's financial condition and liquidity.

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

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

The registrants are subject to risks associated with their ability to obtain adequate insurance at acceptable costs.

The financial condition of some insurance companies, the threat of terrorism, and natural disasters, among other things, could have disruptive effects on insurance markets. The availability of insurance covering risks that the registrants and their respective competitors typically insure against may decrease, and the insurance that the registrants are able to obtain may have higher deductibles, higher premiums, and more restrictive policy terms. Further, the insurance policies may not cover all of the potential exposures or the actual amount of loss incurred. Any losses not covered by insurance, or any increases in the cost of applicable insurance, could adversely affect the results of operations, cash flows, or financial condition of the affected registrant.

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

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

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

Future impairments of goodwill or long-lived assets could have a material adverse effect on the registrants' results of operations.

Goodwill is assessed for impairment at least annually and more frequently if events or circumstances occur that would more likely than not reduce the fair value of a reporting unit below its carrying value and long-lived assets are assessed for impairment whenever events or circumstances indicate that an asset's carrying amount may not be recoverable. In connection with the completion of the Merger, the application of the acquisition method of accounting was pushed down to Southern Company Gas. The excess of the purchase price over the fair values of Southern Company Gas' assets and liabilities was recorded as goodwill. This resulted in a significant increase in the goodwill recorded on Southern Company's and Southern Company Gas' consolidated balance sheets. At December 31, 2017, goodwill was $6.3 billion and $6.0 billion for Southern Company and Southern Company Gas, respectively.

In addition, Southern Company and its subsidiaries have long-lived assets recorded on their balance sheets. To the extent the value of goodwill or long-lived assets become impaired, the affected registrant may be required to incur impairment charges that could have a material impact on their results of operations. For example, a wholly-owned subsidiary of Southern Company

Gas owns and operates a natural gas storage facility consisting of two salt dome caverns where recent seismic mapping indicates that 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. Early retirement of the cavern could trigger impairment of other long-lived assets associated with the natural gas storage facility. In addition, a subsidiary of Southern Company has several leveraged lease agreements, with 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. With respect to Southern Company's subsidiary's investments in leveraged leases, the recovery of its investment is dependent on the profitable operation of the leased assets by the respective lessees. A significant deterioration in the performance of the leased asset could result in the impairment of the related lease receivable.

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Item 1B. UNRESOLVED STAFF COMMENTS.

None.

Item 2. PROPERTIES
Electric
Electric Properties
The traditional electric operating companies, Southern Power, and SEGCO, at December 31, 2017, owned and/or operated 33 hydroelectric generating stations, 29 fossil fuel generating stations, three nuclear generating stations, 15 combined cycle/cogeneration stations, 35 solar facilities, eight wind facilities, one biomass facility, and one landfill gas facility. The amounts of capacity for each company, as of December 31, 2017, are shown in the table below.

| Generating Station | Location | Nameplate Capacity (1) (KWs) | |
|---|---|---|---|
| FOSSIL STEAM | | | |
| Gadsden | Gadsden, AL | 120,000 | |
| Gorgas | Jasper, AL | 1,021,250 | |
| Barry | Mobile, AL | 1,300,000 | |
| Greene County | Demopolis, AL | 300,000 | (2) |
| Gaston Unit 5 | Wilsonville, AL | 880,000 | |
| Miller | Birmingham, AL | 2,532,288 | (3) |
| Alabama Power Total | | 6,153,538 | |
| Bowen | Cartersville, GA | 3,160,000 | |
| Hammond | Rome, GA | 800,000 | |
| McIntosh | Effingham County, GA | 163,117 | |
| Scherer | Macon, GA | 750,924 | (4) |
| Wansley | Carrollton, GA | 925,550 | (5) |
| Yates | Newnan, GA | 700,000 | |
| Georgia Power Total | | 6,499,591 | |
| Crist | Pensacola, FL | 970,000 | |
| Daniel | Pascagoula, MS | 500,000 | (6) |
| Scherer Unit 3 | Macon, GA | 204,500 | (4) |
| Gulf Power Total | | 1,674,500 | |
| Daniel | Pascagoula, MS | 500,000 | (6) |
| Greene County | Demopolis, AL | 200,000 | (2) |
| Watson | Gulfport, MS | 862,000 | |
| Mississippi Power Total | | 1,562,000 | |
| Gaston Units 1-4 | Wilsonville, AL | | |
| SEGCO Total | | 1,000,000 | (7) |
| Total Fossil Steam | | 16,889,629 | |
| NUCLEAR STEAM | | | |
| Farley | Dothan, AL | | |
| Alabama Power Total | | 1,720,000 | |
| Hatch | Baxley, GA | 899,612 | (8) |
| Vogtle Units 1 and 2 | Augusta, GA | 1,060,240 | (9) |
| Georgia Power Total | | 1,959,852 | |
| Total Nuclear Steam | | 3,679,852 | |
| COMBUSTION TURBINES | | | |
| Greene County | Demopolis, AL | | |
| Alabama Power Total | | 720,000 | |
| Boulevard | Savannah, GA | 19,700 | |

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| Generating Station | Location | Nameplate Capacity (1) | |
|---|---|---|---|
| McDonough Unit 3 | Atlanta, GA | 78,800 | |
| McIntosh Units 1 through 8 | Effingham County, GA | 640,000 | |
| McManus | Brunswick, GA | 481,700 | |
| Robins | Warner Robins, GA | 158,400 | |
| Wansley | Carrollton, GA | 26,322 | (5 ) |
| Wilson | Augusta, GA | 354,100 | |
| Georgia Power Total | | 1,759,022 | |
| Lansing Smith Unit A | Southport, FL | 39,400 | |
| Pea Ridge Units 1 through 3 | Pea Ridge, FL | 15,000 | |
| Gulf Power Total | | 54,400 | |
| Chevron Cogenerating Station | Pascagoula, MS | 147,292 | (10) |
| Sweatt | Meridian, MS | 39,400 | |
| Watson | Gulfport, MS | 39,360 | |
| Mississippi Power Total | | 226,052 | |
| Addison | Thomaston, GA | 668,800 | |
| Cleveland County | Cleveland County, NC | 720,000 | |
| Dahlberg | Jackson County, GA | 756,000 | |
| Oleander | Cocoa, FL | 791,301 | |
| Rowan | Salisbury, NC | 455,250 | |
| Southern Power Total | | 3,391,351 | |
| Gaston (SEGCO) | Wilsonville, AL | 19,680 | (7 ) |
| Total Combustion Turbines | | 6,170,505 | |
| COGENERATION | | | |
| Washington County | Washington County, AL | 123,428 | |
| Lowndes County | Burkeville, AL | 104,800 | |
| Theodore | Theodore, AL | 236,418 | |
| Alabama Power Total | | 464,646 | |
| COMBINED CYCLE | | | |
| Barry | Mobile, AL | | |
| Alabama Power Total | | 1,070,424 | |
| McIntosh Units 10&11 | Effingham County, GA | 1,318,920 | |
| McDonough-Atkinson Units 4 through 6 | Atlanta, GA | 2,520,000 | |
| Georgia Power Total | | 3,838,920 | |
| Lansing Smith Unit 3 | Southport, FL | | |
| Gulf Power Total | | 545,500 | |

| Generating Station | Location | Nameplate Capacity (1) | |
|---|---|---|---|
| Daniel | Pascagoula, MS | 1,070,424 | |
| Kemper County/Ratcliffe | Kemper County, MS | 769,898 | (11) |
| Mississippi Power Total | | 1,840,322 | |
| Franklin | Smiths, AL | 1,857,820 | |
| Harris | Autaugaville, AL | 1,318,920 | |
| Mankato | Mankato, MN | 375,000 | |
| Rowan | Salisbury, NC | 530,550 | |
| Stanton Unit A | Orlando, FL | 428,649 | (12 ) |
| Wansley | Carrollton, GA | 1,073,000 | |
| Southern Power Total | | 5,583,939 | |
| Total Combined Cycle | | 12,879,105 | |
| HYDROELECTRIC FACILITIES | | | |
| Bankhead | Holt, AL | 53,985 | |
| Bouldin | Wetumpka, AL | 225,000 | |
| Harris | Wedowee, AL | 132,000 | |
| Henry | Ohatchee, AL | 72,900 | |
| Holt | Holt, AL | 46,944 | |
| Jordan | Wetumpka, AL | 100,000 | |
| Lay | Clanton, AL | 177,000 | |
| Lewis Smith | Jasper, AL | 157,500 | |
| Logan Martin | Vincent, AL | 135,000 | |
| Martin | Dadeville, AL | 182,000 | |
| Mitchell | Verbena, AL | 170,000 | |
| Thurlow | Tallassee, AL | 81,000 | |
| Weiss | Leesburg, AL | 87,750 | |
| Yates | Tallassee, AL | 47,000 | |
| Alabama Power Total | | 1,668,079 | |
| Bartletts Ferry | Columbus, GA | 173,000 | |
| Goat Rock | Columbus, GA | 38,600 | |
| Lloyd Shoals | Jackson, GA | 14,400 | |
| Morgan Falls | Atlanta, GA | 16,800 | |
| North Highlands | Columbus, GA | 29,600 | |
| Oliver Dam | Columbus, GA | 60,000 | |
| Rocky Mountain | Rome, GA | 215,256 | (13 ) |
| Sinclair Dam | Milledgeville, GA | 45,000 | |
| Tallulah Falls | Clayton, GA | 72,000 | |
| Terrora | Clayton, GA | 16,000 | |
| Tugalo | Clayton, GA | 45,000 | |
| Wallace Dam | Eatonton, GA | 321,300 | |
| Yonah | Toccoa, GA | 22,500 | |
| 6 Other Plants | Various Georgia locations | 18,080 | |
| Georgia Power Total | | 1,087,536 | |
| Total Hydroelectric Facilities | | 2,755,615 | |

| Generating Station | Location | Nameplate Capacity (1) | |
|---|---|---|---|
| RENEWABLE SOURCES: | | | |
| SOLAR FACILITIES | | | |
| Fort Benning | Columbus, GA | 30,000 | |
| Fort Gordon | Augusta, GA | 30,000 | |
| Fort Stewart | Fort Stewart, GA | 30,000 | |
| Kings Bay | Camden County, GA | 30,000 | |
| Dalton | Dalton, GA | 6,012 | |
| 3 Other Plants | Various Georgia locations | 2,984 | |
| Georgia Power Total | | 128,996 | |
| Adobe | Kern County, CA | 20,000 | |
| Apex | North Las Vegas, NV | 20,000 | |
| Boulder I | Clark County, NV | 100,000 | (14) |
| Butler | Taylor County, GA | 103,700 | |
| Butler Solar Farm | Taylor County, GA | 22,000 | |
| Calipatria | Imperial County, CA | 20,000 | |
| Campo Verde | Imperial County, CA | 147,420 | |
| Cimarron | Springer, NM | 30,640 | |
| Decatur County | Decatur County, GA | 20,000 | |
| Decatur Parkway | Decatur County, GA | 84,000 | |
| Desert Stateline | San Bernadino County, CA | 299,900 | (14) |
| East Pecos | Pecos County, TX | 120,000 | |
| Garland | Kern County, CA | 205,130 | (14) |
| Granville | Oxford, NC | 2,500 | |
| Henrietta | Kings County, CA | 102,000 | (14) |
| Imperial Valley | Imperial County, CA | 163,200 | (14) |
| Lamesa | Dawson County, TX | 102,000 | |
| Lost Hills - Blackwell | Kern County, CA | 33,440 | (14) |
| Macho Springs | Luna County, NM | 55,000 | |
| Morelos del Sol | Kern County, CA | 15,000 | |
| North Star | Fresno County, CA | 61,600 | (14) |
| Pawpaw | Taylor County, GA | 30,480 | |
| Roserock | Pecos County, TX | 160,000 | (14) |
| Rutherford | Rutherford County, NC | 74,800 | |
| Sandhills | Taylor County, GA | 146,890 | |
| Spectrum | Clark County, NV | 30,240 | |
| Tranquillity | Fresno County, CA | 205,300 | (14) |
| Southern Power Total | | 2,375,240 | (15) |
| Total Solar | | 2,504,236 | |

| Generating Station | Location | Nameplate Capacity (1) | |
|---|---|---|---|
| WIND FACILITIES | | | |
| Bethel | Castro County, TX | 276,000 | |
| Grant Plains | Grant County, OK | 147,200 | |
| Grant Wind | Grant County, OK | 151,800 | |
| Kay Wind | Kay County, OK | 299,000 | |
| Passadumkeag | Penobscot County, ME | 42,900 | |
| Salt Fork | Donley & Gray Counties TX | 174,000 | |
| Tyler Bluff | Cooke County, TX | 125,580 | |
| Wake Wind | Crosby & Floyd Counties, TX | 257,250 | (14) |
| Southern Power Total | | 1,473,730 | |
| LANDFILL GAS FACILITY | | | |
| Perdido | Escambia County, FL | | |
| Gulf Power Total | | 3,200 | |
| BIOMASS FACILITY | | | |
| Nacogdoches | Sacul, TX | | |
| Southern Power Total | | 115,500 | |
| Total Generating Capacity | | 46,936,018 | |

Notes:
(1) See "Jointly-Owned Facilities" herein for additional information.
(2) Owned by Alabama Power and Mississippi Power as tenants in common in the proportions of 60% and 40%, respectively.
(3) Capacity shown is Alabama Power's portion (95.92%) of total plant capacity.
(4) Capacity shown for Georgia Power is 8.4% of Units 1 and 2 and 75% of Unit 3. Capacity shown for Gulf Power is 25% of Unit 3.
(5) Capacity shown is Georgia Power's portion (53.5%) of total plant capacity.
(6) Represents 50% of Plant Daniel Units 1 and 2, which are owned as tenants in common by Gulf Power and Mississippi Power.
(7) SEGCO is jointly-owned by Alabama Power and Georgia Power. See BUSINESS in Item 1 herein for additional information.
(8) Capacity shown is Georgia Power's portion (50.1%) of total plant capacity.
(9) Capacity shown is Georgia Power's portion (45.7%) of total plant capacity.
(10) Generation is dedicated to a single industrial customer.
(11) The capacity shown is the gross capacity using natural gas fuel without supplemental firing.
(12) Capacity shown is Southern Power's portion (65%) of total plant capacity.
(13) Capacity shown is Georgia Power's portion (25.4%) of total plant capacity. OPC operates the plant.
(14) Each facility is owned by Southern Power through a majority-owned subsidiary (90.1% Wake Wind, 66% Desert Stateline, and 51% for each of the following facilities: Boulder 1, Garland, Henrietta, Imperial Valley, Lost Hills-Blackwell, North Star, Roserock, and Tranquillity). The capacity shown in the table is 100% of the nameplate capacity for the respective facility.
(15) 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.

Except as discussed below under "Titles to Property," the principal plants and other important units of the traditional electric operating companies, Southern Power, and SEGCO are owned in fee by the respective companies. It is the opinion of management of each such company that its operating properties are adequately maintained and are substantially in good operating condition, and suitable for their intended purpose.

Mississippi Power owns a 79-mile length of 500-kilovolt transmission line which is leased to Entergy Gulf States Louisiana, LLC. The line, completed in 1984, extends from Plant Daniel to the Louisiana state line. Entergy Gulf

States Louisiana, LLC is

paying a use fee over a 40-year period covering all expenses and the amortization of the original $57 million cost of the line. At December 31, 2017, the unamortized portion of this cost was approximately $13 million.

Mississippi Power owns a lignite mine and equipment that were intended to provide fuel for the Kemper IGCC. Mississippi Power also has acquired mineral reserves located around the Kemper County energy facility. The mine, operated by North American Coal Corporation, started commercial operation in 2013. Liberty Fuels Company, LLC, the operator of the mine, 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 activities to begin in 2018. See MANAGEMENT'S DISCUSSION AND ANALYSIS – FUTURE EARNINGS POTENTIAL – "Kemper County Energy Facility – Lignite Mine and $CO_2$ Pipeline Facilities" of Mississippi Power in Item 7 herein and Note 3 to the financial statements of Southern Company and Mississippi Power under "Kemper County Energy Facility – Lignite Mine and $CO_2$ Pipeline Facilities" in Item 8 herein for additional information on the lignite mine.

In 2018, Mississippi Power will file a reserve margin plan which could impact Mississippi Power's generating stations as well as the generating stations jointly owned by Mississippi Power and other traditional electric operating companies. See BUSINESS in Item 1 herein under "Rate Matters – Integrated Resource Planning – Mississippi Power" for additional information.

In 2017, the maximum demand on the traditional electric operating companies, Southern Power, and SEGCO was 34,874,000 KWs and occurred on August 17, 2017. The all-time maximum demand of 38,777,000 KWs on the traditional electric operating companies, Southern Power, and SEGCO occurred on August 22, 2007. These amounts exclude demand served by capacity retained by MEAG Power, OPC, and SEPA. The reserve margin for the traditional electric operating companies, Southern Power, and SEGCO in 2017 was 30.8%. See SELECTED FINANCIAL DATA in Item 6 herein for additional information.

Jointly-Owned Facilities

Alabama Power, Georgia Power, and Southern Power at December 31, 2017 had undivided interests in certain generating plants and other related facilities with non-affiliated parties. The percentages of ownership of the total plant or facility are as follows:

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

Alabama Power and Georgia Power have contracted to operate and maintain the respective units in which each has an interest (other than Rocky Mountain) as agent for the joint owners. SCS provides operation and maintenance services for Plant Stanton A. Southern Nuclear operates and provides services to Alabama Power's and Georgia Power's nuclear plants.

In addition, Georgia Power has commitments regarding a portion of a 5% interest in Plant Vogtle Units 1 and 2 owned by MEAG Power that are in effect until the later of retirement of the plant or the latest stated maturity date of MEAG Power's bonds issued to finance such ownership interest. The payments for capacity are required whether any capacity is available. The energy cost is a function of each unit's variable operating costs. Except for the portion of the capacity payments related to the Georgia PSC's disallowances of Plant Vogtle Units 1 and 2 costs, the cost of such capacity and energy is included in purchased power from non-affiliates in Georgia Power's statements of income in Item 8 herein.

Also see Note 7 to the financial statements of Georgia Power under "Commitments – Fuel and Purchased Power Agreements" in Item 8 herein for additional information.

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

Titles to Property

The traditional electric operating companies', Southern Power's, and SEGCO's interests in the principal plants (other than certain pollution control facilities and the land on which five combustion turbine generators of Mississippi Power are located, which is held by easement) and other important units of the respective companies are owned in fee by such companies, subject only to the (1) liens pursuant to pollution control revenue bonds of Gulf Power on specific pollution control facilities at Plant Daniel, (2) liens pursuant to the assumption of debt obligations by Mississippi Power in connection with the acquisition of Plant Daniel Units 3 and 4, (3) liens pursuant to the agreements entered into with Mississippi Power's largest customer, Chevron Products Company (Chevron), on October 4, 2017, on the co-generation assets located at the Chevron refinery, (4) liens associated with Georgia Power's reimbursement obligations to the DOE under its loan guarantee, which are secured by a first priority lien on (a) Georgia Power's 45.7% undivided ownership interest in Plant Vogtle Units 3 and 4 and (b) Georgia Power's rights and obligations under the principal contracts relating to Plant Vogtle Units 3 and 4, and (5) liens associated with two PPAs assumed as part of the acquisition of the Mankato project in October 2016 by Southern Power Company. See Note 6 to the financial statements of Southern Company, Georgia Power, Gulf Power, Mississippi Power, and Southern Power under "Assets Subject to Lien," Note 6 to the financial statements of Southern Company and Georgia Power under "DOE Loan Guarantee Borrowings," and Note 6 to the financial statements of Southern Company and Mississippi Power under "Plant Daniel Revenue Bonds" in Item 8 herein for additional information. The traditional electric operating companies own the fee interests in certain of their principal plants as tenants in common. See "Jointly-Owned Facilities" herein for additional information. Properties such as electric transmission and distribution lines, steam heating mains, and gas pipelines are constructed principally on rights-of-way, which are maintained under franchise or are held by easement only. A substantial portion of lands submerged by reservoirs is held under flood right easements. In addition, certain of the renewable generating facilities occupy or use real property that is not owned, primarily through various leases, easements, rights-of-way, permits, or licenses from private landowners or governmental entities.

Natural Gas

Southern Company Gas considers its properties to be adequately maintained, substantially in good operating condition, and suitable for their intended purpose. The following provides the location and general character of the materially important properties that are used by the segments of Southern Company Gas. Substantially all of Nicor Gas' properties are subject to the lien of the indenture securing its first mortgage bonds. See Note 6 to the financial statements of Southern Company Gas under "Long-Term Debt – First Mortgage Bonds" in Item 8 herein for additional information.

Distribution and Transmission Mains – Southern Company Gas' distribution systems transport natural gas from its pipeline suppliers to customers in its service areas. These systems consist primarily of distribution and transmission mains, compressor stations, peak shaving/storage plants, service lines, meters, and regulators. At December 31, 2017, Southern Company Gas' gas distribution operations segment owned approximately 82,000 miles of underground distribution and transmission mains, which are located on easements or rights-of-way that generally provide for perpetual use.

Storage Assets – Gas Distribution Operations – Southern Company Gas owns and operates eight underground natural gas storage facilities in Illinois with a total inventory capacity of approximately 150 Bcf, approximately 135 Bcf of which can be cycled on an annual basis. This system is designed to meet about 50% of the estimated peak-day deliveries and approximately 40% of the normal winter deliveries in Illinois. This level of storage capability provides Nicor Gas with supply flexibility, improves the reliability of deliveries, and helps mitigate the risk associated with seasonal price movements.

Southern Company Gas also has five liquefied natural gas (LNG) plants located in Georgia, New Jersey, and Tennessee with total LNG storage capacity of approximately 7.6 Bcf. In addition, Southern Company Gas owns one propane storage facility in Virginia with storage capacity of approximately 0.3 Bcf. The LNG plants and propane storage facility are used by Southern Company Gas' gas distribution operations segment to supplement natural gas supply during peak usage periods.

Storage Assets – All Other – Southern Company Gas subsidiaries own three high-deliverability natural gas storage and hub facilities that are operated by the gas midstream operations segment. Jefferson Island Storage & Hub, LLC operates a storage facility in Louisiana consisting of two salt dome gas storage caverns. Golden Triangle Storage, Inc. operates a storage facility in Texas consisting of two salt dome caverns. Central Valley Gas Storage, LLC operates a depleted field storage facility in California. In addition, Southern Company Gas has a LNG facility in Alabama that produces LNG for Pivotal LNG, Inc. to support its business of selling LNG as a substitute fuel in various markets.

In August 2017, in connection with an ongoing integrity project into the salt dome gas storage caverns in Louisiana, 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. See FUTURE EARNINGS POTENTIAL – "Other Matters" and Note 3 to the financial statements of Southern Company and Southern Company Gas in Item 8 herein for additional information.

Jointly-Owned Properties – Southern Company Gas' gas midstream operations segment has a 50% undivided ownership interest in a 115-mile pipeline facility in northwest Georgia that was placed in service on August 1, 2017. Southern Company Gas also has an agreement to lease its 50% undivided ownership in the pipeline facility. See Note 4 to the financial statements of Southern Company and Southern Company Gas in Item 8 herein for additional information.

Item 3. LEGAL PROCEEDINGS

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

Item 4. MINE SAFETY DISCLOSURES

Not applicable.

EXECUTIVE OFFICERS OF SOUTHERN COMPANY
(Identification of executive officers of Southern Company is inserted in Part I in accordance with Regulation S-K, Item 401(b), Instruction 3.) The ages of the officers set forth below are as of December 31, 2017.
Thomas A. Fanning
Chairman, President, and Chief Executive Officer
Age 60
Elected in 2003. Chairman and Chief Executive Officer since December 2010 and President since August 2010.
Art P. Beattie
Executive Vice President and Chief Financial Officer
Age 63
Elected in 2010. Executive Vice President and Chief Financial Officer since August 2010.
W. Paul Bowers
Executive Vice President
Age 61
Elected in 2001. Executive Vice President since February 2008 and Chief Executive Officer, President, and Director of Georgia Power since January 2011. Chairman of Georgia Power's Board of Directors since May 2014.
S. W. Connally, Jr.
Chairman, President, and Chief Executive Officer of Gulf Power
Age 48
Elected in 2012. Elected Chairman in July 2015 and President, Chief Executive Officer, and Director of Gulf Power since July 2012.
Mark A. Crosswhite
Executive Vice President
Age 55
Elected in 2010. Executive Vice President since July 2012 and President, Chief Executive Officer, and Director of Alabama Power since March 2014. Chairman of Alabama Power's Board of Directors since May 2014. Previously served as Executive Vice President and Chief Operating Officer of Southern Company from July 2012 through February 2014.
Andrew W. Evans
Executive Vice President
Age 51
Elected in July 2016. Executive Vice President since July 2016. President of Southern Company Gas since May 2015 and Chief Executive Officer and Chairman of Southern Company Gas' Board of Directors since January 2016. Previously served as Chief Operating Officer of Southern Company Gas from May 2015 through December 2015 and Executive Vice President and Chief Financial Officer of Southern Company Gas from May 2006 through May 2015.
Kimberly S. Greene
Executive Vice President
Age 51
Elected in 2013. Executive Vice President and Chief Operating Officer since March 2014. Director of Southern Company Gas since July 2016. Previously served as President and Chief Executive Officer of SCS from April 2013 to February 2014. Before rejoining Southern Company, Ms. Greene served at Tennessee Valley Authority as Executive Vice President and Chief Generation Officer from 2011 through April 2013.
James Y. Kerr II
Executive Vice President and General Counsel
Age 53
Elected in 2014. Also serves as Chief Compliance Officer. Before joining Southern Company, Mr. Kerr was a partner with McGuireWoods LLP and a senior advisor at McGuireWoods Consulting LLC from 2008 through February 2014.
Stephen E. Kuczynski
Chairman, President, and Chief Executive Officer of Southern Nuclear

Age 55
Elected in 2011. Chairman, President, and Chief Executive Officer of Southern Nuclear since July 2011.

Mark S. Lantrip
Executive Vice President
Age 63
Elected in 2014. Chairman, President, and Chief Executive Officer of SCS since March 2014. Previously served as Treasurer of Southern Company from October 2007 to February 2014 and Executive Vice President of SCS from November 2010 to March 2014.
Nancy E. Sykes
Executive Vice President of SCS
Age 49
Elected in 2016. Also serves as Chief Human Resources Officer of SCS. Before joining Southern Company, Ms. Sykes served as vice president and chief human resources officer at United States Steel Corporation from May 2015 to November 2016. Previously served as Vice President, Human Resources Asia-Pacific at Goodyear Tire and Rubber Company from October 2012 until May 2015.
Anthony L. Wilson
Chairman, President, and Chief Executive Officer of Mississippi Power
Age 53
Elected in 2015. President of Mississippi Power since October 2015 and Chief Executive Officer and Director since January 2016. Chairman of Mississippi Power's Board of Directors since August 2016. Previously served as Executive Vice President of Mississippi Power from May 2015 to October 2015 and Executive Vice President of Georgia Power from January 2012 to May 2015.
Christopher C. Womack
Executive Vice President
Age 59
Elected in 2008. Executive Vice President and President of External Affairs since January 2009.
The officers of Southern Company were elected at the first meeting of the directors following the last annual meeting of stockholders held on May 24, 2017, for a term of one year or until their successors are elected and have qualified.

EXECUTIVE OFFICERS OF ALABAMA POWER

(Identification of executive officers of Alabama Power is inserted in Part I in accordance with Regulation S-K, Item 401(b), Instruction 3.) The ages of the officers set forth below are as of December 31, 2017.

Mark A. Crosswhite
Chairman, President, and Chief Executive Officer
Age 55
Elected in 2014. President, Chief Executive Officer, and Director since March 1, 2014. Chairman since May 2014. Previously served as Executive Vice President and Chief Operating Officer of Southern Company from July 2012 through February 2014.

Greg J. Barker
Executive Vice President
Age 54
Elected in 2016. Executive Vice President for Customer Services since February 2016. Previously served as Senior Vice President of Marketing and Economic Development from April 2012 to February 2016.

Philip C. Raymond
Executive Vice President, Chief Financial Officer, and Treasurer
Age 58
Elected in 2010. Executive Vice President, Chief Financial Officer, and Treasurer since August 2010.

Zeke W. Smith
Executive Vice President
Age 58
Elected in 2010. Executive Vice President of External Affairs since November 2010.

James P. Heilbron
Senior Vice President and Senior Production Officer
Age 46
Elected in 2013. Senior Vice President and Senior Production Officer since March 2013. Previously served as Senior Vice President and Senior Production Officer of Southern Power Company from July 2010 to February 2013.

R. Scott Moore
Senior Vice President
Age 50
Elected in 2017. Senior Vice President of Power Delivery since May 2017. Previously served as Vice President of Transmission from August 2012 to May 2017.

The officers of Alabama Power were elected at the meeting of the directors held on April 28, 2017 for a term of one year or until their successors are elected and have qualified, except for Mr. Moore, whose election as Senior Vice President was effective May 20, 2017.

EXECUTIVE OFFICERS OF MISSISSIPPI POWER
(Identification of executive officers of Mississippi Power is inserted in Part I in accordance with Regulation S-K, Item 401(b), Instruction 3.) The ages of the officers set forth below are as of December 31, 2017.
Anthony L. Wilson
Chairman, President, and Chief Executive Officer
Age 53
Elected in 2015. President since October 2015 and Chief Executive Officer and Director since January 2016. Chairman of Mississippi Power's Board since August 2016. Previously served as Executive Vice President from May 2015 to October 2015 and Executive Vice President of Georgia Power from January 2012 to May 2015.
John W. Atherton
Vice President
Age 57
Elected in 2004. Vice President of Corporate Services and Community Relations since October 2012.
A. Nicole Faulk
Vice President
Age 44
Elected in 2015. Vice President of Customer Services Organization effective April 2015. Previously served as Region Vice President for the West Region of Georgia Power from March 2015 through April 2015 and Region Manager for the Metro West Region of Georgia Power from December 2011 to March 2015.
Moses H. Feagin
Vice President, Treasurer, and Chief Financial Officer
Age 53
Elected in 2010. Vice President, Treasurer, and Chief Financial Officer since August 2010.
R. Allen Reaves, Jr.
Vice President
Age 58
Elected in 2010. Vice President and Senior Production Officer since August 2010.
Billy F. Thornton
Vice President
Age 57
Elected in 2012. Vice President of External Affairs since October 2012.
The officers of Mississippi Power were elected at the meeting of the directors held on May 1, 2017 for a term of one year or until their successors are elected and have qualified.

PART II

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

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

| | High | Low |
|---|---|---|
| 2017 | | |
| 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 |

There is no market for the other registrants' common stock, all of which is owned by Southern Company.
(a)(2) Number of Southern Company's common stockholders of record at January 31, 2018: 120,413
Each of the other registrants have one common stockholder, Southern Company.

(a)(3) Dividends on each registrant's common stock are payable at the discretion of their respective board of directors and depend upon earnings, financial condition, and other factors. The dividends on common stock declared by Southern Company, the traditional electric operating companies (other than Mississippi Power), Southern Power Company, and Southern Company Gas to their stockholder(s) for the past two years are set forth below. No dividends were declared by Mississippi Power on its common stock in 2016 or 2017. Southern Company Gas' dividends are only shown for periods subsequent to the Merger.

| Registrant | Quarter | 2017 | 2016 |
|---|---|---|---|
| | | (in thousands) | |
| Southern Company | First | $555,791 | $496,718 |
| | Second | 578,525 | 526,267 |
| | Third | 581,501 | 529,876 |
| | Fourth | 584,015 | 551,110 |
| Alabama Power | First | 178,507 | 191,206 |
| | Second | 178,507 | 191,206 |
| | Third | 178,507 | 191,206 |
| | Fourth | 178,507 | 191,206 |
| Georgia Power | First | 320,242 | 326,269 |
| | Second | 320,242 | 326,269 |
| | Third | 320,242 | 326,269 |
| | Fourth | 320,242 | 326,269 |
| Gulf Power | First | 31,250 | 30,017 |
| | Second | 31,250 | 30,017 |
| | Third | 31,250 | 30,017 |
| | Fourth | 71,250 | 30,017 |
| Southern Power Company | First | 79,211 | 68,082 |
| | Second | 79,211 | 68,082 |
| | Third | 79,211 | 68,082 |
| | Fourth | 79,211 | 68,082 |
| Southern Company Gas | First | 110,641 | — |
| | Second | 110,641 | — |
| | Third | 110,641 | 62,750 |
| | Fourth | 110,641 | 62,750 |

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.

The traditional electric operating companies and Southern Power Company can only pay dividends to Southern Company out of retained earnings or paid-in-capital. The authority of the natural gas distribution utilities to pay dividends to Southern Company Gas is subject to regulation. By regulation, Nicor Gas is restricted, to the extent of its retained earnings balance, in the amount it can dividend or loan to affiliates. Additionally, Elizabethtown Gas is restricted by its policy, as established by the New Jersey Board of Public Utilities, to 70% of its quarterly net income it can dividend to Southern Company Gas. Also, as stipulated in the New Jersey Board of Public Utilities' order approving the Merger, Southern Company Gas is prohibited from paying dividends to its parent company, Southern Company, if Southern Company Gas' senior unsecured debt rating falls below investment grade.

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

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

(b) Use of Proceeds

Not applicable.

(c) Issuer Purchases of Equity Securities

None.

Item 6. SELECTED FINANCIAL DATA



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



Item 7A. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

See MANAGEMENT'S DISCUSSION AND ANALYSIS – FINANCIAL CONDITION AND LIQUIDITY – "Market Price Risk" of each of the registrants in Item 7 herein and Note 1 of each of the registrant's financial statements under "Financial Instruments" in Item 8 herein. See also Notes 10 and 11 to the financial statements of Southern Company, Alabama Power, and Georgia Power, Notes 9 and 10 to the financial statements of Gulf Power, Mississippi Power, and Southern Company Gas, and Notes 8 and 9 to the financial statements of Southern Power in Item 8 herein.

Item 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA
INDEX TO 2017 FINANCIAL STATEMENTS

Table of Contents Index to Financial Statements

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

None.

## Item 9A. CONTROLS AND PROCEDURES

Disclosure Controls and Procedures.

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

Internal Control Over Financial Reporting.

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



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

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

(c) Changes in internal control over financial reporting.

There have been no changes in Southern Company's, Alabama Power's, Georgia Power's, Gulf Power's, Mississippi Power's, Southern Power's, or Southern Company Gas' internal control over financial reporting (as such term is defined in Rules 13a-15(f) and 15d-15(f) under the Securities Exchange Act of 1934, as amended) during the fourth quarter 2017 that have materially affected or are reasonably likely to materially affect Southern Company's, Alabama Power's, Georgia Power's, Gulf Power's, Mississippi Power's, Southern Power's, or Southern Company Gas' internal control over financial reporting.

## Item 9B. OTHER INFORMATION

None.

THE SOUTHERN COMPANY
AND SUBSIDIARY COMPANIES
FINANCIAL SECTION

MANAGEMENT'S REPORT ON INTERNAL CONTROL OVER FINANCIAL REPORTING
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.

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

/s/ Art P. Beattie
Art P. Beattie
Executive Vice President and Chief Financial Officer
February 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 II-64 to II-151) 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 II-8). Our responsibility is to express an opinion on these financial statements and an opinion on the Company's internal control over financial reporting based on our audits. We 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.

/s/ Deloitte & Touche LLP
Atlanta, Georgia
February 20, 2018

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

DEFINITIONS

| Term | Meaning |
|---|---|
| 2012 MPSC CPCN Order | A detailed order issued by the Mississippi PSC in April 2012 confirming the CPCN originally approved by the Mississippi PSC in 2010 authorizing acquisition, construction, and operation of 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 |

DEFINITIONS (continued)

| Term | Meaning |
|---|---|
| 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 |

DEFINITIONS
(continued)

| Term | Meaning |
|---|---|
| $SO_2$ | 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. |
| 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 |

MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS
Southern Company and Subsidiary Companies 2017 Annual Report
OVERVIEW
Business Activities
The Southern Company (Southern Company or the Company) is a holding company that owns all of the common stock of the traditional electric operating companies and the parent entities of Southern Power and Southern Company Gas and owns other direct and indirect subsidiaries. The primary 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

MANAGEMENT'S DISCUSSION AND ANALYSIS (continued)
Southern Company and Subsidiary Companies 2017 Annual Report

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 | | |
|---|---|---|---|
| | 2017 | 2016 | 2015 |
| | (in millions) | | |
| 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 | |
|---|---|---|---|
| | 2017 | 2017 | 2016 |
| | (in millions) | | |
| 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 | |
|---|---|---|
| | 2017 | 2016 |
| | (in millions) | |
| 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

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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:

| | 2017 | 2016 | 2015 |
|---|---|---|---|
| | (in millions) | | |
| 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.

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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.

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A condensed statement of income for the gas business follows:

| | Amount | Increase (Decrease) from Prior Year |
|---|---|---|
| | 2017 | 2017 |
| | (in millions) | |
| 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.

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A condensed statement of income for Southern Company's other business activities follows:

| | Amount | Increase (Decrease) from Prior Year | |
|---|---|---|---|
| | 2017 | 2017 | 2016 |
| | (in millions) | | |
| 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.

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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 $CO_2$ 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 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.

MANAGEMENT'S DISCUSSION AND ANALYSIS (continued)
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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 $CO_2$ 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 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.

MANAGEMENT'S DISCUSSION AND ANALYSIS (continued)
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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.

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Details of short-term borrowings were as follows:

| | Short-term Debt at the End of the Period | | Short-term Debt During the Period (*) | | |
|---|---|---|---|---|---|
| | Amount Outstanding | Weighted Average Interest Rate | Average Amount Outstanding | Weighted Average Interest Rate | Maximum Amount Outstanding |
| | (in millions) | | (in millions) | | (in millions) |
| December 31, 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.

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The changes in fair value of energy-related derivative contracts are substantially attributable to both the volume and the price of natural gas. For the years ended December 31, the changes in fair value of energy-related derivative contracts, the majority of which are composed of regulatory hedges, were as follows:

| | 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 | | | |
|---|---|---|---|---|
| | Total | Maturity | | |
| | Fair Value | Year 1 | Years 2&3 | Years 4&5 |
| | (in millions) | | | |
| 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.

MANAGEMENT'S DISCUSSION AND ANALYSIS (continued)
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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.

MANAGEMENT'S DISCUSSION AND ANALYSIS (continued)
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Contractual Obligations

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

| | 2018 | 2019-2020 | 2021-2022 | After 2022 | Total |
|---|---|---|---|---|---|
| | (in millions) | | | | |
| 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.

MANAGEMENT'S DISCUSSION AND ANALYSIS (continued)
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Cautionary Statement Regarding Forward-Looking Statements

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 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 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 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;
- 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 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 Southern Company and Southern Company Gas will be greater than expected;
- the ability of counterparties of Southern Company and its subsidiaries to make payments as and when due and to perform as required;
- the ability to obtain new short- and long-term contracts with wholesale customers;
- the direct or indirect effect on the Southern Company system's business resulting from cyber intrusion or physical attack and the threat of physical attacks;
- interest rate fluctuations and financial market conditions and the results of financing efforts;
- changes in Southern Company's and any of its subsidiaries' credit ratings, including impacts on interest rates, access to capital markets, and collateral requirements;
- the impacts of any sovereign financial issues, including impacts on interest rates, access to capital markets, impacts on foreign currency exchange rates, counterparty performance, and the economy in general, as well as potential impacts on the benefits of the DOE loan guarantees;
- the ability of Southern Company's electric utilities to obtain additional generating capacity (or sell excess generating capacity) at competitive prices;
- catastrophic events such as fires, earthquakes, explosions, floods, tornadoes, hurricanes and other storms, droughts, pandemic health events such as influenzas, or other similar occurrences;
- the direct or indirect effects on the Southern Company system's business resulting from incidents affecting the U.S. electric grid, natural gas pipeline infrastructure, or operation of generating or storage resources;
- 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 filed by Southern Company from time to time with the SEC.

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

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CONSOLIDATED STATEMENTS OF INCOME
For the Years Ended December 31, 2017, 2016, and 2015
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| | 2017 | 2016 | 2015 |
|---|---|---|---|
| | (in millions) | | |
| 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
Southern Company and Subsidiary Companies 2017 Annual Report

| | 2017 | 2016 | 2015 |
|---|---|---|---|
| | (in millions) | | |
| 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.

Table of Contents Index to Financial Statements

CONSOLIDATED STATEMENTS OF CASH FLOWS
For the Years Ended December 31, 2017, 2016, and 2015
Southern Company and Subsidiary Companies 2017 Annual Report

| | 2017 | 2016 | 2015 |
|---|---|---|---|
| | | (in millions) | |
| 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 ) |
| 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.

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CONSOLIDATED BALANCE SHEETS
At December 31, 2017 and 2016
Southern Company and Subsidiary Companies 2017 Annual Report

| Assets | 2017 | 2016 |
|---|---|---|
| | (in millions) | |
| 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.

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CONSOLIDATED BALANCE SHEETS
At December 31, 2017 and 2016
Southern Company and Subsidiary Companies 2017 Annual Report

| Liabilities and Stockholders' Equity | 2017 | 2016 |
|---|---|---|
| | (in millions) | |
| 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
Southern Company and Subsidiary Companies 2017 Annual Report

| | | 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 % |

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CONSOLIDATED STATEMENTS OF CAPITALIZATION (continued)
At December 31, 2017 and 2016
Southern Company and Subsidiary Companies 2017 Annual Report

| | 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 | — | 196 | | |
| — 2016: 8 million shares | | | | |
| $100 par or stated value — 5.60% to 6.50% | | | | |
| Outstanding — 2017: no shares | — | 368 | | |
| — 2016: 4 million shares | | | | |
| 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.

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CONSOLIDATED STATEMENTS OF STOCKHOLDERS' EQUITY
For the Years Ended December 31, 2017, 2016, and 2015
Southern Company and Subsidiary Companies 2017 Annual Report

| | Southern Company Common Stockholders' Equity | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|
| | Number of Common Shares | | Common Stock | | | | Accumulated Other Comprehensive Income (Loss) | Preferred and Preference Stock of Subsidiaries | Noncontrolling Interests | Total |
| | Issued | Treasury | Par Value | Paid-In Capital | Treasury | Retained Earnings | | | | |
| | (in thousands) | | (in millions) | | | | | | | |
| Balance at December 31, 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) |
| 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 | — | — | — | — | — | — | — | — | 114 | 114 |

| | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|
| interests | | | | | | | | | | |
| 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.

NOTES TO FINANCIAL STATEMENTS
Southern Company and Subsidiary Companies 2017 Annual Report

Index to the Notes to Financial Statements

NOTES (continued)
Southern Company and Subsidiary Companies 2017 Annual Report

1. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES
General
The Southern Company (Southern Company or the Company) is the parent company of four traditional electric operating companies, Southern Power, Southern Company Gas (as of July 1, 2016), SCS, Southern Linc, Southern Company Holdings, Inc. (Southern Holdings), Southern Nuclear, PowerSecure (as of May 9, 2016), and other direct and indirect subsidiaries. The traditional electric operating companies – Alabama Power, Georgia Power, Gulf Power, and Mississippi Power – are vertically integrated utilities providing electric service in four Southeastern states. Southern Power 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.

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

| | 2017 | 2016 | Note |
|---|---|---|---|
| | (in millions) | | |
| 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

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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.

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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:

| | 2017 | 2016 |
|---|---|---|
| | (in millions) | |
| 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, | |
|---|---|---|
| | 2017 | 2016 |
| | (in millions) | |
| 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.

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

| | 2017 | 2016 |
|---|---|---|
| | (in millions) | |
| 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

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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 | |
|---|---|---|
| | 2017 | 2016 |
| | (in millions) | |
| 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.

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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.

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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:

| | Amortization |
|---|---|
| | (in millions) |
| 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:

| | Amortization |
|---|---|
| | (in millions) |
| 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

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"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:

| | 2017 | 2016 |
|---|---|---|
| | (in millions) | |
| 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:

| | 2017 | 2016 | 2015 |
|---|---|---|---|
| | (in millions) | | |
| 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.

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Materials and Supplies

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

Fuel Inventory

Fuel inventory includes the average cost of 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.

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Accumulated OCI (loss) balances, net of tax effects, were as follows:

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

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 |

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| 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:

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

NOTES (continued)
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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:

| | 2017 | 2016 |
|---|---|---|
| | (in millions) | |
| 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:

| | 2017 | 2016 |
|---|---|---|
| | (in millions) | |
| 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 |

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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.

| | Prior Service Cost | Net (Gain) Loss |
|---|---|---|
| | (in millions) | |
| 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:

| | Accumulated OCI | Regulatory Assets |
|---|---|---|
| | (in millions) | |
| 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 |

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Components of net periodic pension cost were as follows:

| | 2017 | 2016 | 2015 |
|---|---|---|---|
| | (in millions) | | |
| 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:

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

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Other Postretirement Benefits

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

| | 2017 | 2016 |
|---|---|---|
| | (in millions) | |
| 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:

| | 2017 | 2016 |
|---|---|---|
| | (in millions) | |
| 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 |

NOTES (continued)
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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.

| | Prior Service Cost | Net (Gain) Loss |
|---|---|---|
| | (in millions) | |
| 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:

| | Accumulated OCI | Net Regulatory Assets (Liabilities) |
|---|---|---|
| | (in millions) | |
| 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 |

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

| | 2017 | 2016 | 2015 |
|---|---|---|---|
| | (in millions) | | |
| 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:

| | Benefit Payments | Subsidy Receipts | Total |
|---|---|---|---|
| | (in millions) | | |
| 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.

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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.<br><br>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.<br><br>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.<br><br>Private equity: Investments in private partnerships that invest in private or public securities typically through privately-negotiated and/or structured transactions, including leveraged buyouts, venture capital, and distressed | Investments in real estate, private equity, and special situations are generally classified as Net Asset Value as a Practical Expedient, since the underlying assets typically do not have publicly available observable inputs. The fund manager values the assets using various inputs and techniques depending on the nature of the underlying investments. Techniques may include purchase multiples for comparable transactions, comparable public company trading multiples, discounted cash flow analysis, prevailing market capitalization rates, recent sales of comparable investments, and independent third-party appraisals. The fair value of partnerships is determined by aggregating the value of the underlying assets less liabilities. |

debt.
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.

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These fair values exclude cash, receivables related to investment income and pending investment sales, and payables related to pending investment purchases.

| | Fair Value Measurements Using | | | | | | |
|---|---|---|---|---|---|---|---|
| As of December 31, 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 | 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.

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| 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.

| 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 |
|---|---|---|---|---|---|
| | (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.

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| | 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 % |

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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.

| | Fair Value Measurements Using | | | | | | |
|---|---|---|---|---|---|---|---|
| | Quoted Prices in Active Markets for Identical Assets | Significant Other Observable Inputs | Significant Unobservable Inputs | Net Asset Value as a Practical Expedient | Total | Target Allocation | Actual Allocation |
| As of December 31, 2017: | (Level 1) | (Level 2) | (Level 3) | (NAV) | | | |
| | (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.

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| | Fair Value Measurements Using | | | | | | |
|---|---|---|---|---|---|---|---|
| As of December 31, 2016: | Quoted Prices in Active Markets for Identical Assets (Level 1) | Significant Other Observable Inputs (Level 2) | Significant Unobservable Inputs (Level 3) | Net Asset Value as a Practical Expedient (NAV) | Total | Target Allocation | Actual Allocation |
| | (in millions) | | | | | | |
| Assets: | | | | | | | |
| Domestic equity(*) | $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.

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| | 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.

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.

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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.

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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.

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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

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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

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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.

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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.

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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

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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.

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.

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5. INCOME TAXES

Southern Company files a consolidated federal income tax return and various state income tax returns, some of which are combined or unitary. Under a joint consolidated income tax allocation agreement, each Southern Company subsidiary's current and deferred tax expense is computed on a stand-alone basis and no subsidiary is allocated more current expense than would be paid if it filed a separate income tax return. PowerSecure and Southern Company Gas became participants in the income tax allocation agreement as of May 9, 2016 and July 1, 2016, respectively. In accordance with IRS regulations, each company is jointly and severally liable for the federal tax liability.

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:

| | 2017 | 2016 | 2015 |
|---|---|---|---|
| | (in millions) | | |
| 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.

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The tax effects of temporary differences between the carrying amounts of assets and liabilities in the financial statements and their respective tax bases, which give rise to deferred tax assets and liabilities, are as follows:

| | 2017 | 2016 |
|---|---|---|
| | (in millions) | |
| 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 | |

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

| | 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:

| | 2017 | 2016 | 2015 |
|---|---|---|---|
| | (in millions) | | |
| 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

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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:

| | 2017 | 2016 | 2015 |
|---|---|---|---|
| | (in millions) | | |
| 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.

6. FINANCING

Securities Due Within One Year

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

| | 2017 | 2016 |
|---|---|---|
| | (in millions) | |
| 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.

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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.

NOTES (continued)
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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.

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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.

NOTES (continued)
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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 1/4 of 1% for Southern Company, the traditional electric operating companies, Southern Power Company, Southern Company Gas, and Nicor Gas. Compensating balances are not legally restricted from withdrawal.

Subject to applicable market conditions, Southern Company and its subsidiaries expect to renew or replace their bank credit arrangements as needed, prior to expiration. In connection therewith, Southern Company and its subsidiaries may extend the maturity dates and/or increase or decrease the lending commitments thereunder.

Southern Company's, Southern Company Gas', and Nicor Gas' credit arrangements contain covenants that limit debt levels to 70% of total capitalization, as defined in the agreements, and most of 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.

NOTES (continued)
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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:

| | Redeemable Preferred Stock of Subsidiaries (in millions) |
|---|---|
| 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 |

NOTES (continued)
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7. COMMITMENTS
Fuel and Purchased Power Agreements
To supply a portion of the fuel requirements of the generating plants, the Southern Company system has entered into various long-term commitments for the procurement and delivery of fossil and nuclear fuel which are not recognized on the balance sheets. In 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:

| | Operating Leases | Other |
|---|---|---|
| | (in millions) | |
| 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:

| | Pipeline Charges, Storage Capacity, and Gas Supply |
|---|---|
| | (in millions) |
| 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.

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

| | Minimum Lease Payments | | |
|---|---|---|---|
| | Barges & Railcars | Other(*) | Total |
| | (in millions) | | |
| 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.

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 (in millions) | Weighted Average Exercise Price |
|---|---|---|
| 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 | | |
|---|---|---|---|
| | 2017 | 2016 | 2015 |
| | (in millions) | | |
| 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.

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.

## 10. FAIR VALUE MEASUREMENTS

Fair value measurements are based on inputs of observable and unobservable market data that a market participant would use in pricing the asset or liability. The use of observable inputs is maximized where available and the use of unobservable inputs is minimized for fair value measurement and reflects a three-tier fair value hierarchy that prioritizes inputs to valuation techniques used for fair value measurement.

- Level 1 consists of observable market data in an active market for identical assets or liabilities.
- Level 2 consists of observable market data, other than that included in Level 1, that is either directly or indirectly observable.
- Level 3 consists of unobservable market data. The input may reflect the assumptions of the Company of what a market participant would use in pricing an asset or liability. If there is little available market data, then the Company's own assumptions are the best available information.

In the case of multiple inputs being used in a fair value measurement, the lowest level input that is significant to the fair value measurement represents the level in the fair value hierarchy in which the fair value measurement is reported.

NOTES (continued)
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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 | | | | |
|---|---|---|---|---|---|
| | Quoted Prices in Active Markets for Identical Assets | Significant Other Observable Inputs | Significant Unobservable Inputs | Net Asset Value as a Practical Expedient | |
| As of December 31, 2017: | (Level 1) | (Level 2) | (Level 3) | (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.

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As of December 31, 2016, assets and liabilities measured at fair value on a recurring basis during the period, together with their associated level of the fair value hierarchy, were as follows:

| | Fair Value Measurements Using | | | | |
|---|---|---|---|---|---|
| | Quoted Prices in Active Markets for Identical Assets | Significant Other Observable Inputs | Significant Unobservable Inputs | Net Asset Value as a Practical Expedient | |
| As of December 31, 2016: | (Level 1) | (Level 2) | (Level 3) | (NAV) | Total |
| | (in millions) | | | | |
| Assets: | | | | | |
| Energy-related derivatives[(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

NOTES (continued)
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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:

| | Carrying Amount | Fair Value |
|---|---|---|
| | (in millions) | |
| 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.

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

NOTES (continued)
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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.

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Interest Rate Derivatives

Southern Company and certain subsidiaries may also enter into interest rate derivatives to hedge exposure to changes in interest rates. The derivatives employed as hedging instruments are structured to minimize ineffectiveness. Derivatives related to existing variable rate securities or forecasted transactions are accounted for as cash flow hedges where the effective portion of the derivatives' fair value gains or losses is recorded in OCI and is reclassified into earnings at the same time the hedged transactions affect earnings, with any ineffectiveness recorded directly to earnings. Derivatives related to existing fixed rate securities are accounted for as fair value hedges, where the derivatives' fair value gains or losses and hedged items' fair value gains or losses are both recorded directly to earnings, providing an offset, with any difference representing ineffectiveness. Fair value gains or losses on derivatives that are not designated or fail to qualify as hedges are recognized in the statements of income as incurred. At December 31, 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.

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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.

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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 Assets | 2017 Liabilities | 2016 Assets | 2016 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:

| Derivative Category | Unrealized Losses Balance Sheet Location | 2017 | 2016 | Unrealized Gains 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) | | | Gain (Loss) Reclassified from Accumulated OCI into Income (Effective Portion) | | | |
|---|---|---|---|---|---|---|---|
| | Amount | | | | 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.

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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

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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.

## 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.

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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

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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 Class B | (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:

| | 2017 (in millions) |
|---|---|
| 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

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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%.

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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:

| | 2016 (in millions) |
|---|---|
| CWIP | $ 2,354 |
| Property, plant, and equipment | 302 |
| Intangible assets [(a)] | 128 |
| Other assets | 52 |
| Accounts payable | (16 ) |
| Debt | (217 ) |
| Total purchase price | $ 2,603 |
| | |
| Funded by: | |
| Southern Power [(b)] [(c)] | $ 2,345 |
| Noncontrolling interests [(d)] [(e)] | 258 |
| Total purchase price | $ 2,603 |

(a) Intangible assets consist of acquired PPAs that will be amortized over 10- and 20-year terms. The estimated amortization for future periods is approximately $9 million per year. 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

NOTES (continued)
Southern Company and Subsidiary Companies 2017 Annual Report

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.
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:

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Southern Company and Subsidiary Companies 2017 Annual Report

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

NOTES (continued)
Southern Company and Subsidiary Companies 2017 Annual Report

Products and Services

Electric Utilities' Revenues

| Year | 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 |

Southern Company Gas' Revenues

| Year | 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 |

NOTES (continued)
Southern Company and Subsidiary Companies 2017 Annual Report

14. QUARTERLY FINANCIAL INFORMATION (UNAUDITED)

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

| Quarter Ended | Operating Revenues | Operating Income | Consolidated Net Income Attributable to Southern Company | Per Common Share Basic Earnings | Diluted Earnings | Dividends | Trading Price Range High | Low |
|---|---|---|---|---|---|---|---|---|
| | (in millions) | | | | | | | |
| March 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
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| | 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.

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SELECTED CONSOLIDATED FINANCIAL AND OPERATING DATA (continued)
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| | 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)
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| | 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.

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MANAGEMENT'S REPORT ON INTERNAL CONTROL OVER FINANCIAL REPORTING
Alabama Power Company 2017 Annual Report

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

Under management's supervision, an evaluation of the design and effectiveness of the Company's internal control over financial reporting was conducted based on the framework in Internal Control—Integrated Framework (2013) issued by the Committee of Sponsoring Organizations of the Treadway Commission. Based on this evaluation, management concluded that the Company's internal control over financial reporting was effective as of December 31, 2017.

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

/s/ Philip C. Raymond
Philip C. Raymond
Executive Vice President, Chief Financial Officer, and Treasurer
February 20, 2018

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the stockholders and the Board of Directors of Alabama Power Company

Opinion on the Financial Statements

We have audited the accompanying balance sheets and statements of capitalization of Alabama Power Company (the Company) (a wholly-owned subsidiary of The Southern Company) as of December 31, 2017 and 2016, the related statements of income, comprehensive income, common stockholder's equity, and cash flows for each of the three years in the period ended December 31, 2017, and the related notes (collectively referred to as the "financial statements"). In our opinion, the financial statements (pages II-186 to II-231) 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.

Basis for Opinion

These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on the Company's financial statements 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 audit to obtain reasonable assurance about whether the financial statements are free of material misstatement, whether due to error or fraud. The Company is not required to have, nor were we engaged to perform, an audit of its internal control over financial reporting. As part of our audits, we are required to obtain an understanding of internal control over financial reporting but not for the purpose of expressing an opinion on the effectiveness of the Company's internal control over financial reporting. Accordingly, we express no such opinion. Our audits included performing procedures to assess the risks of material misstatement of the financial statements, whether due to error or fraud, and performing procedures that 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. We believe that our audits provide a reasonable basis for our opinion.

/s/ Deloitte & Touche LLP

Birmingham, Alabama

February 20, 2018

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

DEFINITIONS

| Term | Meaning |
|---|---|
| AFUDC | Allowance for funds used during construction |
| ARO | Asset retirement obligation |
| ASC | Accounting Standards Codification |
| ASU | Accounting Standards Update |
| CCR | Coal combustion residuals |
| Clean Air Act | Clean Air Act Amendments of 1990 |
| $CO_2$ | Carbon dioxide |
| DOE | U.S. Department of Energy |
| EPA | U.S. Environmental Protection Agency |
| FASB | Financial Accounting Standards Board |
| FERC | Federal Energy Regulatory Commission |
| GAAP | U.S. generally accepted accounting principles |
| Georgia Power | Georgia Power Company |
| Gulf Power | Gulf Power Company |
| IRS | Internal Revenue Service |
| ITC | Investment tax credit |
| KWH | Kilowatt-hour |
| LIBOR | London Interbank Offered Rate |
| Mississippi Power | Mississippi Power Company |
| mmBtu | Million British thermal units |
| Moody's | Moody's Investors Service, Inc. |
| MW | Megawatt |
| NDR | Natural Disaster Reserve |
| $NO_X$ | Nitrogen oxide |
| NRC | U.S. Nuclear Regulatory Commission |
| OCI | Other comprehensive income |
| power pool | The operating arrangement whereby the integrated generating resources of the traditional electric operating companies and Southern Power (excluding subsidiaries) are subject to joint commitment and dispatch in order to serve their combined load obligations |
| PPA | Power purchase agreement |
| PSC | Public Service Commission |
| Rate CNP | Rate Certificated New Plant |
| Rate CNP Compliance | Rate Certificated New Plant Compliance |
| Rate CNP PPA | Rate Certificated New Plant Power Purchase Agreement |
| Rate ECR | Rate Energy Cost Recovery |
| Rate NDR | Rate Natural Disaster Reserve |
| Rate RSE | Rate Stabilization and Equalization plan |
| ROE | Return on equity |
| S&P | S&P Global Ratings, a division of S&P Global Inc. |
| SCS | Southern Company Services, Inc. (the Southern Company system service company) |
| SEC | U.S. Securities and Exchange Commission |
| SEGCO | Southern Electric Generating Company |
| $SO_2$ | Sulfur dioxide |
| Southern Company | The Southern Company |

| | |
|---|---|
| Southern Company Gas | Southern Company Gas and its subsidiaries |

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DEFINITIONS
(continued)

| Term | Meaning |
|---|---|
| Southern Company system | Southern Company, the traditional electric operating companies, Southern Power, Southern Company Gas (as of July 1, 2016), SEGCO, Southern Nuclear, SCS, Southern Linc, PowerSecure, Inc. (as of May 9, 2016), and other subsidiaries |
| Southern Linc | Southern Communications Services, Inc. |
| Southern Nuclear | Southern Nuclear Operating Company, Inc. |
| Southern Power | Southern Power Company and its subsidiaries |
| 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 |
| traditional electric operating companies | Alabama Power Company, Georgia Power, Gulf Power, and Mississippi Power |

MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS
Alabama Power Company 2017 Annual Report
OVERVIEW
Business Activities
Alabama Power Company (the Company) operates as a vertically integrated utility providing electric service to retail and wholesale customers within its traditional service territory located in the State of Alabama in addition to wholesale customers in the Southeast.
Many factors affect the opportunities, challenges, and risks of the Company's business of providing electric service. These factors include the ability to maintain a constructive regulatory environment, to maintain and grow energy sales and 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, capital expenditures, and restoration following major storms. The Company has various regulatory mechanisms that operate to address cost recovery. Effectively operating pursuant to these regulatory mechanisms and appropriately balancing required costs and capital expenditures with customer prices will continue to challenge the Company for the foreseeable future.
The Company continues to focus on several key performance indicators including, but not limited to, customer satisfaction, plant availability, system reliability, and net income after dividends on preferred and preference stock. The Company's financial success is directly tied to customer satisfaction. Key elements of ensuring customer satisfaction include outstanding service, high reliability, and competitive prices. Management uses customer satisfaction surveys to evaluate the Company's results and generally targets the top quartile of these surveys in measuring performance.
See RESULTS OF OPERATIONS herein for information on the Company's financial performance.
Earnings
The Company's 2017 net income after dividends on preferred and preference stock was $848 million, representing a $26 million, or 3.2%, increase over the previous year. The increase was primarily due to an increase in rates under Rate RSE effective in January 2017 and the impact of a Rate RSE refund recorded in 2016. These increases to income were partially offset by a decrease in retail revenues associated with milder weather, lower customer usage, and an increase in non-fuel operations and maintenance expenses in 2017 as compared to 2016. See FUTURE EARNINGS POTENTIAL – "Retail Regulatory Matters – Rate RSE" herein for additional information.
The Company's 2016 net income after dividends on preferred and preference stock was $822 million, representing a $37 million, or 4.7%, increase over the previous year. The increase was due primarily to an increase in retail revenues under Rate CNP Compliance, an increase in weather-related revenues, and a decrease in operations and maintenance expenses not related to fuel or Rate CNP Compliance. These increases to income were partially offset by an accrual for a Rate RSE refund, a decrease in AFUDC equity, and an increase in depreciation.

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RESULTS OF OPERATIONS

A condensed income statement for the Company follows:

| | Amount | Increase (Decrease) from Prior Year | |
|---|---|---|---|
| | 2017 | 2017 | 2016 |
| | (in millions) | | |
| Operating revenues | $6,039 | $ 150 | $ 121 |
| Fuel | 1,225 | (72) | (45) |
| Purchased power | 328 | (6) | (17) |
| Other operations and maintenance | 1,652 | 142 | 9 |
| Depreciation and amortization | 736 | 33 | 60 |
| Taxes other than income taxes | 384 | 4 | 12 |
| Total operating expenses | 4,325 | 101 | 19 |
| Operating income | 1,714 | 49 | 102 |
| Allowance for equity funds used during construction | 39 | 11 | (32) |
| Interest expense, net of amounts capitalized | 305 | 3 | 28 |
| Other income (expense), net | (14) | 7 | 11 |
| Income taxes | 568 | 37 | 25 |
| Net income | 866 | 27 | 28 |
| Dividends on preferred and preference stock | 18 | 1 | (9) |
| Net income after dividends on preferred and preference stock | $848 | $ 26 | $ 37 |

Operating Revenues

Operating revenues for 2017 were $6.0 billion, reflecting a $150 million increase from 2016. Details of operating revenues were as follows:

| | Amount | |
|---|---|---|
| | 2017 | 2016 |
| | (in millions) | |
| Retail — prior year | $5,322 | $5,234 |
| Estimated change resulting from — | | |
| Rates and pricing | 362 | 147 |
| Sales decline | (44) | (20) |
| Weather | (89) | 31 |
| Fuel and other cost recovery | (93) | (70) |
| Retail — current year | 5,458 | 5,322 |
| Wholesale revenues — | | |
| Non-affiliates | 276 | 283 |
| Affiliates | 97 | 69 |
| Total wholesale revenues | 373 | 352 |
| Other operating revenues | 208 | 215 |
| Total operating revenues | $6,039 | $5,889 |
| Percent change | 2.6 % | 2.1 % |

Retail revenues in 2017 were $5.5 billion. These revenues increased $136 million, or 2.6%, in 2017 and $88 million, or 1.7%, in 2016, each as compared to the prior year. The increase in 2017 was primarily due to an increase in rates under Rate RSE effective in January 2017, partially offset by a decrease in fuel revenues and milder weather in the first and third quarters 2017

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as compared to the corresponding periods in 2016. The increase in 2016 was due to an increase in revenues under Rate CNP Compliance as a result of increased net investments, partially offset by a decrease in fuel revenues and an accrual for a Rate RSE refund. See Note 3 to the financial statements under "Retail Regulatory Matters – Rate RSE" for additional information. See "Energy Sales" herein for a discussion of changes in the volume of energy sold, including changes related to sales decline and weather.

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

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

| | 2017 | 2016 | 2015 |
|---|---|---|---|
| | (in millions) | | |
| Capacity and other | $154 | $154 | $140 |
| Energy | 122 | 129 | 101 |
| Total non-affiliated | $276 | $283 | $241 |

Wholesale revenues from sales to non-affiliates will vary depending on fuel prices, the market prices of wholesale energy compared to the cost of the Company's and the Southern Company system's generation, demand for energy within the Southern Company system's electric service territory, and availability of the Southern Company system's generation. Increases and decreases in energy revenues that are driven by fuel prices are accompanied by an increase or decrease in fuel costs and do not affect net income. Short-term opportunity energy sales are also included in wholesale energy sales to non-affiliates. These opportunity sales are made at market-based rates that generally provide a margin above the Company's variable cost to produce the energy.

In 2017, wholesale revenues from sales to non-affiliates decreased $7 million, or 2.5%, as compared to the prior year. In 2016, wholesale revenues from sales to non-affiliates increased $42 million, or 17.4%, as compared to the prior year primarily due to a $28 million increase in revenues from energy sales and a $14 million increase in capacity revenues. In 2016, KWH sales increased 33.3% primarily due to a new contract that became effective in the first quarter 2016 partially offset by a 12.1% decrease in the price of energy due to lower natural gas prices.

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

In 2017, wholesale revenues from sales to affiliates increased $28 million, or 40.6%, as compared to the prior year. In 2017, KWH sales increased 31.1% as a result of supporting Southern Company system transmission reliability and a 6.9% increase in the price of energy primarily due to higher natural gas prices. In 2016, wholesale revenues from sales to affiliates decreased $15 million, or 17.9%, as compared to the prior year. In 2016, KWH sales decreased 15.7% as a result of lower-cost generation available in the Southern Company system and a 2.6% decrease in the price of energy primarily due to lower natural gas prices.

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Energy Sales

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

| | Total KWHs 2017 (in billions) | Total KWH Percent Change 2017 | Total KWH Percent Change 2016 | Weather-Adjusted Percent Change 2017 | Weather-Adjusted Percent Change 2016 |
|---|---|---|---|---|---|
| Residential | 17.2 | (6.1 )% | 1.4 % | (1.2 )% | (0.5 )% |
| Commercial | 13.6 | (3.4 ) | (0.1 ) | (1.3 ) | (0.5 ) |
| Industrial | 22.7 | 1.7 | (4.6 ) | 1.7 | (4.6 ) |
| Other | 0.2 | (5.0 ) | 3.8 | (5.0 ) | 3.8 |
| Total retail | 53.7 | (2.3 ) | (1.5 ) | (0.1 )% | (2.2 )% |
| Wholesale | | | | | |
| Non-affiliates | 5.5 | (6.5 ) | 37.1 | | |
| Affiliates | 4.2 | 31.1 | (15.7 ) | | |
| Total wholesale | 9.7 | 6.6 | 12.5 | | |
| Total energy sales | 63.4 | (1.0 )% | 0.3 % | | |

Changes in retail energy sales are generally the result of changes in electricity usage by customers, changes in weather, and changes in the number of customers. Retail energy sales in 2017 were 2.3% lower than in 2016. Residential sales and commercial sales decreased 6.1% and 3.4% in 2017, respectively, primarily due to milder weather in the first and third quarters 2017 as compared to the corresponding periods in 2016. Weather-adjusted residential sales were 1.2% lower in 2017 primarily due to lower customer usage resulting from an increase in penetration of energy-efficient residential appliances, partially offset by customer growth. Weather-adjusted commercial sales were 1.3% lower in 2017 primarily due to lower 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 sales increased 1.7% in 2017 as compared to 2016 as a result of an increase in demand resulting from changes in production levels primarily in the primary metals, chemicals, and mining sectors offset by the pipelines and paper sectors.

Retail energy sales in 2016 were 1.5% lower than in 2015. Residential sales increased 1.4% primarily due to warmer weather in the third quarter 2016 as compared to the corresponding period in 2015. Commercial sales remained flat in 2016. Weather-adjusted residential sales were flat in 2016 due to lower customer usage primarily resulting from an increase in efficiency improvements in residential appliances and lighting, partially offset by customer growth. Industrial sales decreased 4.6% in 2016 compared to 2015 as a result of a decrease in demand resulting from changes in production levels primarily in the primary metals, chemical, pipelines, paper, and stone, clay, and glass sectors. A strong dollar, low oil prices, and weak global growth conditions constrained growth in the industrial sector in 2016.

See "Operating Revenues" above for a discussion of significant changes in wholesale revenues from sales to non-affiliates and wholesale revenues from sales to affiliated companies as related to changes in price and KWH sales.

Fuel and Purchased Power Expenses

Fuel costs constitute one of the largest expenses for the Company. The mix of fuel sources for generation of electricity is determined primarily by the unit cost of fuel consumed, demand, and the availability of generating units. Additionally, the Company purchases a portion of its electricity needs from the wholesale market.

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

| | 2017 | 2016 | 2015 |
|---|---|---|---|
| Total generation (in billions of KWHs) | 60.3 | 60.2 | 60.9 |
| Total purchased power (in billions of KWHs) | 6.4 | 7.1 | 6.3 |
| Sources of generation (percent) — | | | |
| Coal | 50 | 53 | 54 |
| Nuclear | 24 | 23 | 24 |
| Gas | 20 | 19 | 16 |
| Hydro | 6 | 5 | 6 |
| Cost of fuel, generated (in cents per net KWH) — | | | |
| Coal | 2.60 | 2.75 | 2.83 |
| Nuclear | 0.75 | 0.78 | 0.81 |
| Gas | 2.72 | 2.67 | 2.94 |
| Average cost of fuel, generated (in cents per net KWH)[(a)] | 2.14 | 2.26 | 2.34 |
| Average cost of purchased power (in cents per net KWH)[(b)] | 5.29 | 4.80 | 5.66 |

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

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

Fuel and purchased power expenses were $1.55 billion in 2017, a decrease of $78 million, or 4.8%, compared to 2016. The decrease was primarily due to a $67 million net decrease related to the volume of KWHs generated and purchased and a $42 million decrease in the average cost of fuel, partially offset by a $31 million increase in the average cost of purchased power.

Fuel and purchased power expenses were $1.63 billion in 2016, a decrease of $62 million, or 3.7%, compared to 2015. The decrease was primarily due to a $61 million decrease in the average cost of purchased power, and a $59 million decrease in the average cost of fuel, partially offset by a $49 million increase related to the volume of KWHs purchased.

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

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

Fuel

Fuel expenses were $1.2 billion in 2017, a decrease of $72 million, or 5.6%, compared to 2016. The decrease was primarily due to a 12.2% increase in the volume of KWHs generated by hydro, a 5.8% decrease in the volume of KWHs generated by coal, and a 5.5% and 3.9% decrease in the average cost of KWHs generated by coal and nuclear fuel, respectively. These decreases were partially offset by an 8.1% increase in the volume of KWHs generated by nuclear fuel and a 4.0% increase in the volume of KWHs generated by natural gas. Fuel expenses were $1.3 billion in 2016, a decrease of $45 million, or 3.4%, compared to 2015. The decrease was primarily due to a 9.2% decrease in the average cost of KWHs generated by natural gas, which excludes tolling agreements, a 4.2% and 3.9% decrease in the volume of KWHs generated by nuclear fuel and coal, respectively, and a 3.7% decrease in the average cost of KWHs generated by nuclear fuel, partially offset by a 17.4% increase in the volume of KWHs generated by natural gas.

Purchased Power – Affiliates

Purchased power expense from affiliates was $158 million in 2017, a decrease of $10 million, or 6.0%, compared to 2016. This decrease was primarily due to a 17.2% decrease in the amount of energy purchased due to milder weather partially offset by a 13.9% increase in the average cost per KWH purchased due to higher natural gas prices.
Purchased power expense from affiliates was $168 million in 2016, a decrease of $12 million, or 6.7%, compared to 2015. This decrease was primarily due to a

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20.7% decrease in the average cost per KWH purchased due to lower natural gas prices, partially offset by a 17.5% increase in the amount of energy purchased due to the availability of lower-cost generation compared to the Company's owned generation.

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

Other Operations and Maintenance Expenses

In 2017, other operations and maintenance expenses increased $142 million, or 9.4%, as compared to the prior year. Distribution and transmission expenses increased $58 million primarily due to vegetation management expenses. Generation costs increased $38 million primarily due to outage costs. Employee benefit costs, including pension costs, increased $22 million.

In 2016, other operations and maintenance expenses increased $9 million, or 0.6%, as compared to the prior year. Steam production costs increased $28 million primarily due to the timing of generation operating expenses. Transmission and distribution expenses increased $10 million and $7 million, respectively, primarily due to additional vegetation management and other maintenance expenses. These increases were partially offset by a decrease of $32 million in employee benefit costs, including pension costs. The increases in operations and maintenance expenses were primarily Rate CNP compliance-related costs and therefore had no significant impact to net income. See FUTURE EARNINGS POTENTIAL – "Retail Regulatory Matters – Rate CNP Compliance" herein for additional information.

See Note 2 to the financial statements under "Pension Plans" for additional information.

Depreciation and Amortization

Depreciation and amortization increased $33 million, or 4.7%, in 2017 as compared to the prior year primarily due to additional plant in service and an increase in generation-related depreciation rates, effective January 1, 2017, associated with compliance-related steam projects and ARO recovery, partially offset by a decrease in distribution-related depreciation rates. See Note 1 to the financial statements under "Depreciation and Amortization" for additional information. Depreciation and amortization increased $60 million, or 9.3%, in 2016 as compared to the prior year primarily due to compliance-related steam projects placed in service.

Taxes Other Than Income Taxes

Taxes other than income taxes increased $4 million, or 1.1%, in 2017 as compared to the prior year. In 2016, taxes other than income taxes increased $12 million, or 3.3% in 2016 as compared to the prior year. The increase was primarily due to increases in state and municipal utility license tax bases primarily due to an increase in retail revenues. In addition, ad valorem taxes increased primarily due to an increase in assessed value of property.

Allowance for Equity Funds Used During Construction

AFUDC equity increased $11 million, or 39.3%, in 2017 as compared to the prior year. The increase was primarily associated with steam, transmission, and nuclear construction projects. AFUDC equity decreased $32 million, or 53.3%, in 2016 as compared to the prior year. The decrease was primarily associated with steam generation capital projects being placed in service. See Note 1 to financial statements under "Allowance for Funds Used During Construction" for additional information.

Interest Expense, Net of Amounts Capitalized

Interest expense, net of amounts capitalized increased $3 million, or 1.0%, in 2017 as compared to the prior year. Interest expense, net of amounts capitalized increased $28 million, or 10.2%, in 2016 as compared to the prior year primarily due to an increase in debt outstanding and a reduction in the amounts capitalized. See FUTURE EARNINGS POTENTIAL – "Financing Activities" herein for additional information.

Other Income (Expense), Net

Other income (expense), net increased $7 million, or 33.3%, in 2017 as compared to the prior year primarily due to increases in unregulated lighting services. Other income (expense), net increased $11 million, or 34.4%, in 2016 as compared to the prior year primarily due to a decrease in donations, partially offset by a decrease in sales of non-utility property.

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Income Taxes

Income taxes increased $37 million, or 7.0%, in 2017 as compared to the prior year primarily due to higher pre-tax earnings, an increase in prior year tax return actualization, and an increase in income tax reserves, partially offset by an increase in state income tax credits. The impact to income taxes as a result of Tax Reform Legislation was not material due to the application of regulatory accounting. See FUTURE EARNINGS POTENTIAL – "Income Tax Matters – Federal Tax Reform Legislation" herein and Note 5 to the financial statements for additional information.

Income taxes increased $25 million, or 4.9%, in 2016 as compared to the prior year primarily due to higher pre-tax earnings.

Dividends on Preferred and Preference Stock

Dividends on preferred and preference stock increased $1 million, or 5.9%, in 2017 as compared to the prior year.

Dividends on preferred and preference stock decreased $9 million, or 34.6%, in 2016 as compared to the prior year. The decrease was primarily due to the redemption in May 2015 of certain series of preferred and preference stock. See Note 6 to the financial statements under "Redeemable Preferred and Preference Stock" for additional information.

Effects of Inflation

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

FUTURE EARNINGS POTENTIAL

General

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

The results of operations for the past three years are not necessarily indicative of future earnings potential. The level of the Company's future earnings depends on numerous factors that affect the opportunities, challenges, and risks of the Company's primary business of providing electric service. These factors include the Company's ability to maintain a constructive regulatory environment that continues to allow for the timely recovery of prudently-incurred costs during a time of increasing costs and limited projected demand growth over the next several years. Future earnings will be impacted by customer growth. Earnings will also depend upon maintaining and growing sales, considering, among other things, the adoption and/or penetration rates of increasingly energy-efficient technologies and increasing volumes of electronic commerce transactions, both of which could contribute to a net reduction in customer usage.

Earnings are subject to a variety of other factors. These factors include weather, competition, new energy contracts with other utilities, energy conservation practiced by customers, the use of alternative energy sources by customers, the price of electricity, the price elasticity of demand, and the rate of economic growth or decline in the Company's service territory. Demand for electricity is primarily driven by the pace of economic growth that may be affected by changes in regional and global economic conditions, which may impact future earnings.

On December 22, 2017, 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 under

"Retail Regulatory Matters – Rate RSE" and "Current and Deferred Income Taxes," respectively, for additional information.

Environmental Matters

The Company'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 Company 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

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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 Company's 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. Environmental compliance costs are recovered through Rate CNP Compliance. See Note 3 to the financial statements under "Retail Regulatory Matters – Rate CNP Compliance" for additional information. Further, increased costs that are recovered through regulated rates could contribute to reduced demand for electricity, which could negatively affect results of operations, cash flows, and financial condition. 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.

Through 2017, the Company has invested approximately $4.7 billion in environmental capital retrofit projects to comply with environmental requirements, with annual totals of approximately $491 million, $260 million, and $349 million 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 Company's current compliance strategy estimates capital expenditures of $1.4 billion from 2018 through 2022, with annual totals of approximately $581 million in 2018, $110 million in 2019, $163 million in 2020, $258 million in 2021, and $268 million in 2022. 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 Company 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. No areas within the Company's 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 Company-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 Company has fossil fuel-fired generation 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. 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 the 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.

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In 2015, the EPA published a final rule requiring certain states (including Alabama) 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 Company.

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 Company's 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. The Company continues to monitor the ELG rule and anticipates that approximately 1,000 MWs of the Company's generation will not be available after the compliance date. The ultimate impact of this rule will depend on any new rule-making that revises the limitation and applicable dates. The Company does not anticipate that the unavailability of any units as a result of the ELG rule will have a material impact on the Company's operations or financial condition.

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 and distribution 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.
Based on cost estimates for closure in place and monitoring of ash ponds pursuant to the CCR Rule, the Company recorded AROs for each CCR unit in 2015. As further analysis is performed and closure details are developed, the Company 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 the Company's AROs as of December 31, 2017.

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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.

The EPA's GHG reporting rule requires annual reporting of GHG emissions expressed in terms of metric tons of $CO_2$ equivalent emissions for a company's operational control of facilities. Based on ownership or financial control of facilities, the Company's 2016 GHG emissions were approximately 38 million metric tons of $CO_2$ equivalent. The preliminary estimate of the Company's 2017 GHG emissions on the same basis is approximately 37 million metric tons of $CO_2$ equivalent.

FERC Matters

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

In December 2016, the traditional electric operating companies (including the Company) and Southern Power filed an amendment to their market-based rate tariff that proposed certain changes to the energy auction, as well as several non-tariff changes. On February 2, 2017, the FERC issued an order accepting all such changes subject to an additional condition of cost-based price caps for certain sales outside of the energy auction, finding that all of these changes would provide adequate alternative mitigation for the traditional electric operating companies' (including the Company's) and Southern Power's potential to exert market power in certain areas served by the traditional electric operating companies (including the Company) and in some adjacent areas. On May 17, 2017, the FERC accepted the traditional electric operating companies' (including the Company's) 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' (including the Company's) and Southern Power's June 29, 2017 triennial updated market power analysis. The FERC directed the traditional electric operating companies (including the Company) 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 (including the Company) 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.

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Retail Regulatory Matters

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

Rate RSE

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

At December 31, 2016, the Company's retail return exceeded the allowed WCE range which resulted in the Company establishing a $73 million Rate RSE refund liability. In accordance with an Alabama PSC order issued on February 14, 2017, the Company 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, the Company's actual retail return was within the allowed WCE range. On December 1, 2017, the Company 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, the Company 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

The Company'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. The Company 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 the Company 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, the Company eliminated the under recovered balance in Rate CNP PPA at December 31, 2016, which totaled approximately $142 million. As discussed herein under "Rate RSE," the Company 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 the Company's next depreciation study, which is expected to occur within the next two to four years. The Company's current depreciation study became effective January 1, 2017.

Rate CNP Compliance

Rate CNP Compliance allows for the recovery of the Company's retail costs associated with laws, regulations, and other such mandates directed at the utility industry involving the environment, security, reliability, safety, sustainability, or similar considerations impacting the Company's facilities or operations. Rate CNP Compliance is based on forward-looking information and provides for the recovery of these costs pursuant to a factor that is calculated annually. Compliance costs to be recovered include operations and maintenance expenses, depreciation, and a return on certain invested capital. Revenues for Rate CNP Compliance, as recorded on the financial statements, are adjusted for differences in actual recoverable costs and amounts billed in current regulated rates. Accordingly, changes in the billing factor will have no significant effect on the Company's revenues or net income, but will affect annual cash flow. Changes in 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, the Company reclassified $36 million of its under recovered balance in Rate CNP Compliance to a separate regulatory asset. The amortization of the new regulatory

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asset through Rate RSE will begin concurrently with the effective date of the Company's next depreciation study, which is expected to occur within the next two to four years. The Company's current depreciation study became effective January 1, 2017.

On December 5, 2017, the Alabama PSC issued a consent order that the Company leave in effect for 2018 the factors associated with the Company'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.

Rate ECR

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

In accordance with an accounting order issued on February 17, 2017 by the Alabama PSC, the Company 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 the Company's next depreciation study, which is expected to occur within the next two to four years. The Company's current depreciation study became effective January 1, 2017.

On December 5, 2017, the Alabama PSC issued a consent order that the Company 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.

Rate NDR

Based on an order from the Alabama PSC, the Company maintains a reserve for operations and maintenance expenses to cover the cost of damages from major storms to its transmission and distribution facilities. The order approves a separate monthly Rate NDR charge to customers consisting of two components. The first component is intended to establish and maintain a reserve balance for future storms and is an on-going part of customer billing. 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.

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. The Company 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, the Company is allowed to establish a regulatory asset to record the unrecovered investment costs, including the unrecovered plant asset balance and the unrecovered costs associated with site removal and closure associated with future unit retirements caused by environmental regulations. 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.

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.

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Regulated utility businesses 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, net operating losses (NOL) 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 in the subsequent tax year. The projected reduction of Southern Company's 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 expense of $3 million, a $271 million decrease in regulatory assets, and a $2.0 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.

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 the Alabama PSC. On January 31, 2018, SCS, on behalf of the traditional electric operating companies (including the Company), filed with the FERC a reduction to the Company's open access transmission tariff charge for 2018 to reflect the revised federal corporate tax rate. See Note 3 to the financial statements under "Regulatory Matters – Rate RSE" for additional information.

See FINANCIAL CONDITION AND LIQUIDITY – "Credit Rating Risk" herein and Note 5 to the financial statements under "Federal Tax Reform Legislation" 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, approximately $200 million of positive cash flows is expected to result from bonus depreciation for the 2017 tax year and approximately $90 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. See Note 5 to the financial statements under "Current and Deferred Income Taxes" for additional information.

Other Matters

The Company is involved in various other matters being litigated and regulatory matters that could affect future earnings. In addition, the Company is subject to certain claims and legal actions arising in the ordinary course of business. The Company's business activities are subject to extensive governmental regulation related to public health and the environment, such as regulation of air emissions and water discharges. Litigation over environmental issues and claims of various types, including property damage, personal injury, common law nuisance, and citizen enforcement of environmental requirements such as 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 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 the Company's financial statements. See Note 3 to the financial statements for a discussion of various other contingencies, regulatory matters, and other matters being litigated which may affect future earnings potential.

ACCOUNTING POLICIES

Application of Critical Accounting Policies and Estimates

The Company prepares its financial statements in accordance with GAAP. Significant accounting policies are described in Note 1 to the financial statements. In the application of these policies, certain estimates are made that may have a material impact on the Company's results of operations and related disclosures. Different assumptions and measurements could produce estimates that

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are significantly different from those recorded in the financial statements. Senior management has reviewed and discussed the following critical accounting policies and estimates with the Audit Committee of Southern Company's Board of Directors.

Utility Regulation

The Company is subject to retail regulation by the Alabama PSC and wholesale regulation by the FERC. As a result, the Company applies accounting standards which require the financial statements to reflect the effects of rate regulation. Through the ratemaking process, the regulators may require the inclusion of costs or revenues in periods different than when they would be recognized by a non-regulated company. This treatment may result in the deferral of expenses and the recording of related regulatory assets based on anticipated future recovery through rates or the deferral of gains or creation of liabilities and the recording of related regulatory liabilities. The application of the accounting standards has a further effect on the Company's financial statements as a result of the estimates of allowable costs used in the ratemaking process. These estimates may differ from those actually incurred by the Company; therefore, the accounting estimates inherent in specific costs such as depreciation, AROs, and pension and other postretirement benefits have less of a direct impact on the Company's results of operations and financial condition than they would on a non-regulated company.

As reflected in Note 1 to the financial statements, significant regulatory assets and liabilities have been recorded. Management reviews the ultimate recoverability of these regulatory assets and any requirement to refund these regulatory liabilities based on applicable regulatory guidelines and GAAP. However, adverse legislative, judicial, or regulatory actions could materially impact the amounts of such regulatory assets and liabilities and could adversely impact the Company's financial statements.

Federal Tax Reform Legislation

Following the enactment of 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, the Company considers all amounts recorded in the financial statements as a result of Tax Reform Legislation to be "provisional" as discussed in SAB 118 and subject to revision. The Company is awaiting additional guidance from industry and income tax authorities in order to finalize its accounting. The ultimate impact of 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 "Retail Regulatory Matters – Rate RSE" 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 the decommissioning of the Company's nuclear facility, Plant Farley, and facilities that are subject to the CCR Rule, principally ash ponds. In addition, the Company has retirement obligations related to various landfill sites, underground storage tanks, asbestos removal related to ongoing repair and maintenance, disposal of polychlorinated biphenyls in certain transformers, and disposal of sulfur hexafluoride gas in certain substation breakers. The Company also has identified retirement obligations related to certain transmission and distribution facilities, asbestos containing material within long-term assets not subject to ongoing repair and maintenance activities, and certain wireless communication towers. However, liabilities for the removal of these assets have not been recorded because the settlement timing for the retirement obligations related to these assets is indeterminable and, therefore, the fair value of the retirement obligations cannot be reasonably estimated. A liability for these AROs will be recognized when sufficient information becomes available to support a reasonable estimation of the ARO.

The cost estimates for AROs related to the disposal of CCR are based on information using various assumptions related to closure and post-closure costs, timing of future cash outlays, inflation and discount rates, and the potential methods for complying with the CCR Rule requirements for closure in place. As further analysis is performed and closure details are developed, the Company 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, the Company considers the liabilities for AROs to be critical accounting estimates.

Pension and Other Postretirement Benefits

The Company's calculation of pension and other postretirement benefits expense is dependent on a number of assumptions. These assumptions include discount rates, healthcare cost trend rates, expected long-term return on plan assets, mortality rates, expected salary and wage increases, and other factors. Components of pension and other postretirement benefits expense include interest and service cost on the pension and other postretirement benefit plans, expected return on plan assets, and amortization of certain unrecognized costs and obligations. Actual results that differ from the assumptions utilized are accumulated and amortized over future periods and, therefore, generally affect recognized expense and the recorded obligation in future periods. While the Company believes that the assumptions used are appropriate, differences in actual experience or significant changes in assumptions would affect its pension and other postretirement benefits costs and obligations.

Key elements in determining the Company's pension and other postretirement benefit expense are the expected long-term return on plan assets and the discount rate used to measure the benefit plan obligations and the periodic benefit plan expense for future periods. The expected long-term return on pension and other postretirement benefit plan assets is based on the Company's investment strategy, historical experience, and expectations for long-term rates of return that consider external actuarial advice. The Company determines the long-term return on plan assets by applying the long-term rate of expected returns on various asset classes to the Company's target asset allocation. For purposes of determining its liability related to the pension and other postretirement benefit plans, the Company discounts the future related cash flows using a single-point discount rate developed from the weighted average of market-observed yields for high quality fixed income securities with maturities that correspond to expected benefit payments. For 2015 and prior years, the Company computed the interest cost component of its net periodic pension and other postretirement benefit plan expense using the same single-point discount rate. Beginning in 2016, the Company adopted a full yield curve approach for calculating the interest cost component whereby the discount rate for each year is applied to the liability for that specific year. As a result, the interest cost component of net periodic pension and other postretirement benefit plan expense decreased by approximately $24 million in 2016.

A 25 basis point change in any significant assumption (discount rate, salaries, or long-term return on plan assets) would result in an $9 million or less change in total annual benefit expense and a $128 million or less change in projected obligations.

The Company recorded pension costs of $9 million, $11 million, and $48 million in 2017, 2016, and 2015, respectively. Postretirement benefit costs for the Company were $3 million, $4 million, and $5 million in 2017, 2016, and 2015, respectively. Such amounts are dependent on several factors including trust earnings and changes to the plans. A portion of pension and other postretirement benefit costs is capitalized based on construction-related labor charges. Pension and other postretirement benefit costs are a component of the regulated rates and generally do not have a long-term effect on net income.

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

Contingent Obligations

The Company is subject to a number of federal and state laws and regulations, as well as other factors and conditions that subject it to environmental, litigation, and other risks. See FUTURE EARNINGS POTENTIAL herein and Note 3 to the financial statements for more information regarding certain of these contingencies. The Company periodically evaluates its exposure to such risks and records reserves for those matters where a non-tax-related loss is considered probable and reasonably estimable. The adequacy of reserves can be significantly affected by external events or conditions that can be unpredictable; thus, the ultimate outcome of such matters could materially affect the Company's results of operations, cash flows, or financial condition.

Recently Issued Accounting Standards

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 the Company's revenue, including energy provided to customers, is from tariff offerings that provide electricity without a defined contractual term, as well as longer-term contractual commitments, including PPAs.

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The 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 energy-related derivatives, are excluded from the scope of ASC 606 and, therefore, will be accounted for and disclosed separately from revenues under ASC 606. The 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. The Company applied the modified retrospective method of adoption effective January 1, 2018. The 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. ASU 2016-02 is effective for fiscal years beginning after December 15, 2018 and the Company will adopt the new standard effective January 1, 2019.
The 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, the 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, railcars, and a PPA where the Company is the lessee and outdoor lighting and to land where the Company is the lessor. The Company is currently analyzing pole attachment agreements and a lease determination has not been made at this time. While the Company has not yet determined the ultimate impact, adoption of ASU 2016-02 is expected to have a significant impact on the Company's balance sheet.

Other

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 the 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. The 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. The Company adopted ASU 2017-12 effective January 1, 2018 with no material impact on its financial statements.

FINANCIAL CONDITION AND LIQUIDITY

Overview

The Company's financial condition remained stable at December 31, 2017. The Company's cash requirements primarily consist of funding ongoing operations, common stock dividends, capital expenditures, and debt maturities. Capital expenditures and other investing activities include investments to meet projected long-term demand requirements, to maintain existing generation facilities, to comply with environmental regulations including adding environmental modifications to certain existing generating units, to expand and improve transmission and distribution facilities, and for restoration following major storms. Operating cash flows provide a substantial portion of the Company's cash needs. For the three-year period from 2018 through 2020, the Company's projected common stock dividends, capital expenditures, and debt maturities are expected to exceed operating cash flows. The Company plans to finance future cash needs in excess of its operating cash flows primarily through external securities issuances, borrowings from financial institutions, or equity contributions from Southern Company. The Company plans to use commercial paper to manage seasonal variations in operating cash flows and for other working capital needs. The Company intends to continue to monitor its access to short-term and long-term capital markets as well as its bank credit arrangements to meet future capital and liquidity needs. See "Sources of Capital," "Financing Activities," and "Capital Requirements and Contractual Obligations" herein for additional information.

The Company's investments in the qualified pension plan and the nuclear decommissioning trust funds increased in value as of December 31, 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 plan are anticipated during 2018. The Company's funding obligations for the nuclear decommissioning trust fund are based on the most recent site study, and the next study is expected to be conducted in 2018. See Notes 1 and 2 to the financial statements under "Nuclear Decommissioning" and "Pension Plans," respectively, for additional information.

Net cash provided from operating activities totaled $1.8 billion for 2017, a decrease of $112 million as compared to 2016. The decrease in cash provided from operating activities was primarily due to the timing of income tax payments in 2017 and the receipt of income tax refunds in 2016 as a result of bonus depreciation, partially offset by the voluntary contribution to the qualified pension plan in 2016. Net cash provided from operating activities totaled $1.9 billion for 2016, a decrease of $193 million as compared to 2015. The decrease in cash provided from operating activities was primarily due to the collection of fuel cost recovery revenues and the voluntary contribution to the qualified pension plan, partially offset by the timing of income tax payments and refunds associated with bonus depreciation.

Net cash used for investing activities totaled $1.9 billion for 2017, $1.4 billion for 2016, and $1.5 billion for 2015. These activities were primarily related to gross property additions for environmental, steam generation, distribution, and transmission assets.

Net cash provided from financing activities totaled $163 million in 2017 primarily due to issuances of long-term debt and additional capital contributions from Southern Company, partially offset by the payment of common stock dividends and maturities of long-term debt. Net cash used for financing activities totaled $285 million in 2016 primarily due to the payment of common stock dividends and a redemption of long-term debt, partially offset by issuances of long-term debt and additional capital contributions from Southern Company. Fluctuations in cash flow from financing activities vary from year to year based on capital needs and the maturity or redemption of securities.

Significant balance sheet changes for 2017 included increases of $1.3 billion in property, plant, and equipment primarily due to additions to distribution and transmission facilities and environmental and steam generation assets and $1.1 billion in long-term debt. Other significant changes included an increase of $2.0 billion in deferred credits related to income taxes and decreases of $1.9 billion in accumulated deferred income taxes primarily due to the change in tax rate resulting from Tax Reform Legislation and $0.6 billion in securities due within one year. See FUTURE EARNINGS POTENTIAL – "Income Tax Matters – Federal Tax Reform Legislation" herein and Note 5 to the financial statements for additional information.

The Company's ratio of common equity to total capitalization plus short-term debt was 46.3% and 46.2% at December 31, 2017 and 2016, respectively. See Note 6 to the financial statements for additional information.

Sources of Capital

The Company plans to obtain the funds to meet its future capital needs from sources similar to those used in the past, which were primarily from operating cash flows, external security issuances, borrowings from financial institutions, and equity contributions from Southern Company. However, the amount, type, and timing of any future financings, if needed, will depend upon prevailing market conditions, regulatory approval, and other factors.

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

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MANAGEMENT'S DISCUSSION AND ANALYSIS (continued)
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The Company obtains financing separately without credit support from any affiliate. See Note 6 to the financial statements under "Bank Credit Arrangements" for additional information. The Southern Company system does not maintain a centralized cash or money pool. Therefore, funds of the Company are not commingled with funds of any other company in the Southern Company system.
The Company's current liabilities sometimes exceed current assets because of long-term debt maturities and the periodic use of short-term debt as a funding source, as well as significant seasonal fluctuations in cash needs.
At December 31, 2017, the Company had approximately $544 million of cash and cash equivalents. Committed credit arrangements with banks at December 31, 2017 were as follows:

| Expires | | | | | Expires Within One Year | |
|---|---|---|---|---|---|---|
| 2018 | 2020 | 2022 | Total | Unused | Term Out | No Term Out |
| (in millions) | | | (in millions) | | (in millions) | |
| $35 | $500 | $800 | $1,335 | $1,335 | $ — | $ 35 |

See Note 6 to the financial statements under "Bank Credit Arrangements" for additional information.
In May 2017 and September 2017, the Company amended its $800 million and $500 million multi-year credit arrangements, which, among other things, extended the maturity dates from 2020 to 2022 and 2018 to 2020, respectively, as reflected in the table above.
Most of these bank credit arrangements, as well as the Company's term loan arrangements, contain covenants that limit debt levels and contain cross-acceleration provisions to other indebtedness (including guarantee obligations) of the Company. Such cross-acceleration provisions to other indebtedness would trigger an event of default if the Company defaulted on indebtedness, the payment of which was then accelerated. At December 31, 2017, the Company was in compliance with all such covenants. None of the bank credit arrangements contain material adverse change clauses at the time of borrowings.
Subject to applicable market conditions, the Company expects to renew or replace its bank credit arrangements as needed, prior to expiration. In connection therewith, the Company may extend the maturity dates and/or increase or decrease the lending commitments thereunder.
A portion of the unused credit with banks is allocated to provide liquidity support to the Company's pollution control revenue bonds and commercial paper programs. The amount of variable rate pollution control revenue bonds outstanding requiring liquidity support was $854 million as of December 31, 2017. In addition, at December 31, 2017, the Company had $120 million of fixed rate pollution control revenue bonds outstanding that were required to be remarketed within the next 12 months.
The Company also has substantial cash flow from operating activities and access to the capital markets, including a commercial paper program, to meet liquidity needs. The Company may meet short-term cash needs through its commercial paper program. The Company may also meet short-term cash needs through a Southern Company subsidiary organized to issue and sell commercial paper at the request and for the benefit of the Company and the other traditional electric operating companies. Proceeds from such issuances for the benefit of the Company are loaned directly to the Company. The obligations of each traditional electric operating company under these arrangements are several and there is no cross-affiliate credit support.
Details of short-term borrowings were as follows:

| | Short-term Debt at the End of the | Short-term Debt During the Period (*) |
|---|---|---|

| 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 | $ 3 | 3.7 % | $25 | 1.3 % | $ 223 |
| December 31, 2016 | $ — | — % | $16 | 0.6 % | $ 200 |
| December 31, 2015 | $ — | — % | $14 | 0.2 % | $ 100 |

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

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

MANAGEMENT'S DISCUSSION AND ANALYSIS (continued)
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Financing Activities
In February 2017, the Company repaid at maturity $200 million aggregate principal amount of Series 2007A 5.55% Senior Notes.
In March 2017, the Company issued $550 million aggregate principal amount of Series 2017A 2.45% Senior Notes due March 30, 2022. The proceeds were used to repay the Company's short-term indebtedness and for general corporate purposes, including the Company's continuous construction program.
In August 2017, the Company repaid at maturity $36.1 million aggregate principal amount of Series 1993-A, 1993-B, and 1993-C Industrial Development Board of the City of Mobile, Alabama Pollution Control Revenue Refunding Bonds (Alabama Power Company Project).
In September 2017, the Company 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 proceeds were used in October 2017 to redeem all 2 million shares ($50 million aggregate stated capital) of 6.50% Series Preference Stock, 6 million shares ($150 million aggregate stated capital) of 6.45% Series Preference Stock, and 1.52 million shares ($38 million aggregate stated capital) of 5.83% Class A Preferred Stock and for other general corporate purposes, including the Company's continuous construction program.
In October 2017, the Company repaid at maturity $325 million aggregate principal amount of Series Q 5.50% Senior Notes.
In November 2017, the Company issued $550 million aggregate principal amount of Series 2017B 3.70% Senior Notes due December 1, 2047. The proceeds were used for general corporate purposes, including the Company's continuous construction program.
In addition to any financings that may be necessary to meet capital requirements and contractual obligations, the Company plans to continue, when economically feasible, a program to retire higher-cost securities and replace these obligations with lower-cost capital if market conditions permit.
Credit Rating Risk
At December 31, 2017, the Company did not have any credit arrangements that would require material changes in payment schedules or terminations as a result of a credit rating downgrade.
There are certain contracts that could require collateral, but not accelerated payment, in the event of a credit rating change to BBB and/or Baa2 or below. These contracts are primarily for physical electricity purchases, fuel purchases, fuel transportation and storage, energy price risk management, and transmission.
The maximum potential collateral requirements under these contracts at December 31, 2017 were as follows:

| Credit Ratings | Maximum Potential Collateral Requirements | |
|---|---|---|
| | (in millions) | |
| At BBB and/or Baa2 | $ | 1 |
| At BBB- and/or Baa3 | $ | 2 |
| Below BBB- and/or Baa3 | $ | 323 |

Included in these amounts are certain agreements that could require collateral in the event that either the Company or Georgia Power has a credit rating change to below investment grade. Generally, collateral may be provided by a Southern Company guaranty, letter of credit, or cash. Additionally, a credit rating downgrade could impact the ability of the Company to access capital markets and would be likely to impact the cost at which it does so.
On March 24, 2017, S&P revised its consolidated credit rating outlook for Southern Company and its subsidiaries (including the Company) from stable to negative.
On January 19, 2018, Moody's revised its rating outlook for the Company from stable to negative.
While it is unclear how the credit rating agencies and regulatory authorities 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, including the Company, may be negatively impacted. Absent actions by Southern Company and its subsidiaries, including the Company, to mitigate the resulting impacts, which, among other alternatives, could include adjusting capital structure and/or monetizing regulatory assets, the Company's credit ratings could be negatively affected. See Note 3 to the financial statements under "Retail Regulatory Matters – Rate RSE" for additional information.

MANAGEMENT'S DISCUSSION AND ANALYSIS (continued)
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Market Price Risk

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

To mitigate future exposure to changes in interest rates, the Company may enter into derivatives designated as hedges. The weighted average interest rate on $1.1 billion of long-term variable interest rate exposure at December 31, 2017 was 2.3%. If the Company sustained a 100 basis point change in interest rates for all long-term variable interest rate exposure, the change would affect annualized interest expense by approximately $11 million at December 31, 2017. See Note 1 to the financial statements under "Financial Instruments" and Note 11 to the financial statements for additional information.

To mitigate residual risks relative to movements in electricity prices, the Company enters into physical fixed-price contracts for the purchase and sale of electricity through the wholesale electricity market and financial hedge contracts for natural gas purchases. The Company continues to manage a retail fuel-hedging program implemented per the guidelines of the Alabama PSC. The Company had no material change in market risk exposure for the year ended December 31, 2017 when compared to the year ended December 31, 2016.

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

The changes in fair value of energy-related derivative contracts are substantially attributable to both the volume and the price of natural gas. For the years ended December 31, the changes in fair value of energy-related derivative contracts, the majority of which are composed of regulatory hedges, were as follows:

| | 2017 Changes | 2016 Changes |
|---|---|---|
| | Fair Value | |
| | (in millions) | |
| Contracts outstanding at the beginning of the period, assets (liabilities), net | $12 | $ (54 ) |
| Contracts realized or settled | (1 ) | 39 |
| Current period changes(*) | (17 ) | 27 |
| Contracts outstanding at the end of the period, assets (liabilities), net | $(6 ) | $ 12 |

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

The net hedge volumes of energy-related derivative contracts, for the years ended December 31 were as follows:

| | 2017 | 2016 |
|---|---|---|
| | mmBtu Volume (in millions) | |
| Commodity – Natural gas swaps | 64 | 68 |

| | | |
|---|---|---|
| Commodity – Natural gas options | 5 | 6 |
| Total hedge volume | 69 | 74 |

The weighted average swap contract cost above market prices was approximately $0.08 per mmBtu as of December 31, 2017 and below market prices was approximately $0.14 per mmBtu as of December 31, 2016. The change in option fair value is primarily attributable to the volatility of the market and the underlying change in the natural gas price. Substantially all of the natural gas hedge gains and losses are recovered through the Company's retail energy cost recovery clause.

MANAGEMENT'S DISCUSSION AND ANALYSIS (continued)
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At December 31, 2017 and 2016, substantially all of the Company's energy-related derivative contracts were designated as regulatory hedges and were related to the Company's fuel-hedging program. Therefore, gains and losses are initially recorded as regulatory liabilities and assets, respectively, and then are included in fuel expense as they are recovered through the energy cost recovery clause. Certain other gains and losses on energy-related derivatives, designated as cash flow hedges, are initially deferred in OCI before being recognized in income in the same period as the hedged transaction. Gains and losses on energy-related derivative contracts that are not designated or fail to qualify as hedges are recognized in the statements of income as incurred and were not material for any year presented. The Company uses over-the-counter contracts that are not exchange traded but are fair valued using prices which are market observable, and thus fall into Level 2 of the fair value hierarchy. See Note 10 to the financial statements for further discussion of fair value measurements. The maturities of the energy-related derivative contracts, which are primarily Level 2 of the fair value hierarchy, at December 31, 2017 were as follows:

| | Fair Value Measurements December 31, 2017 | | |
|---|---|---|---|
| | Total Fair Value | Maturity Year 1 | Years 2&3 |
| | (in millions) | | |
| Level 1 | $ — | $ — | $ — |
| Level 2 | 6 | 4 | 2 |
| Level 3 | — | — | — |
| Fair value of contracts outstanding at end of period | $ 6 | $ 4 | $ 2 |

The Company is exposed to market price risk in the event of nonperformance by counterparties to energy-related and interest rate derivative contracts. The Company only enters into agreements and material transactions with counterparties that have investment grade credit ratings by Moody's and S&P, or with counterparties who have posted collateral to cover potential credit exposure. Therefore, the Company does not anticipate market risk exposure from nonperformance by the counterparties. For additional information, see Note 1 to the financial statements under "Financial Instruments" and Note 11 to the financial statements.

Capital Requirements and Contractual Obligations

The construction program of the Company is currently estimated to total $2.2 billion for 2018, $1.6 billion for 2019, $1.6 billion for 2020, $1.7 billion for 2021, and $1.4 billion for 2022. The construction program includes capital expenditures related to contractual purchase commitments for nuclear fuel and capital expenditures covered under long-term service agreements. Estimated capital expenditures to comply with environmental laws and regulations included in these amounts are $581 million for 2018, $110 million for 2019, $163 million for 2020, $258 million for 2021, and $268 million for 2022. 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 Company also anticipates costs associated with closure in place and monitoring of ash ponds in accordance with the CCR Rule, which are reflected in the Company's ARO liabilities. These costs, which could change as the Company continues to refine its assumptions underlying the cost estimates and evaluate the method and timing of compliance activities, are estimated to be $0.3 million for 2018, $111 million for 2019, $90 million for 2020, $94 million for 2021, and $96 million for 2022. See Note 1 to the financial statements under "Asset Retirement Obligations and Other Costs of Removal" for additional information. Costs associated with the CCR Rule are expected to be recovered through Rate CNP Compliance.

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

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

In addition, as discussed in Note 2 to the financial statements, the Company provides postretirement benefits to substantially all employees and funds trusts to the extent required by the Alabama PSC and the FERC.

Other funding requirements related to obligations associated with scheduled maturities of long-term debt, as well as the related interest, derivative obligations, pension and other postretirement benefit plans, preferred stock dividends, leases, and other purchase commitments are detailed in the contractual obligations table that follows. See Notes 1, 2, 6, 7, and 11 to the financial statements for additional information.

MANAGEMENT'S DISCUSSION AND ANALYSIS (continued)
Alabama Power Company 2017 Annual Report

Contractual Obligations

Contractual obligations at December 31, 2017 were as follows:

| | 2018 | 2019-2020 | 2021-2022 | After 2022 | Total |
|---|---|---|---|---|---|
| | (in millions) | | | | |
| Long-term debt[a] — | | | | | |
| Principal | $— | $450 | $1,060 | $6,176 | $7,686 |
| Interest | 304 | 598 | 561 | 4,408 | 5,871 |
| Preferred stock dividends[b] | 15 | 29 | 29 | — | 73 |
| Financial derivative obligations[c] | 6 | 4 | — | — | 10 |
| Operating leases[d] | 21 | 40 | 24 | 20 | 105 |
| Capital Lease | 1 | 1 | 1 | 2 | 5 |
| Purchase commitments — | | | | | |
| Capital[e] | 2,053 | 2,972 | 2,914 | — | 7,939 |
| Fuel[f] | 974 | 1,197 | 459 | 238 | 2,868 |
| Purchased power[g] | 78 | 171 | 186 | 606 | 1,041 |
| Other[h] | 47 | 73 | 59 | 313 | 492 |
| Pension and other postretirement benefit plans[i] | 19 | 36 | — | — | 55 |
| Total | $3,518 | $5,571 | $5,293 | $11,763 | $26,145 |

(a) All amounts are reflected based on final maturity dates. The Company plans to continue, when economically feasible, to retire higher-cost securities and replace these obligations with lower-cost capital if market conditions permit. Variable rate interest obligations are estimated based on rates as of 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) Preferred stock does not mature; therefore, amounts are provided for the next five years only.

(c) Includes derivative liabilities related to cash flow hedges of forecasted debt, as well as energy-related derivatives. For additional information, see Notes 1 and 11 to the financial statements.

(d) Excludes PPAs that are accounted for as leases and are included in purchased power.

(e) The Company provides estimated capital expenditures for a five-year period, including capital expenditures associated with environmental regulations. These amounts exclude contractual purchase commitments for nuclear fuel and capital expenditures covered under long-term service agreements which are reflected in "Fuel" and "Other," respectively. At December 31, 2017, purchase commitments were outstanding in connection with the construction program. See FUTURE EARNINGS POTENTIAL – "Environmental Matters – Environmental Laws and Regulations" herein for additional information.

(f) Includes commitments to purchase coal, nuclear fuel, and natural gas, as well as the related transportation and storage. In most cases, these contracts contain provisions for price escalation, minimum purchase levels, and other financial commitments. Natural gas purchase commitments are based on various indices at the time of delivery. Amounts reflected for natural gas purchase commitments have been estimated based on the New York Mercantile Exchange future prices at December 31, 2017.

(g) Estimated minimum long-term obligations for various long-term commitments for the purchase of capacity and energy.

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

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

MANAGEMENT'S DISCUSSION AND ANALYSIS (continued)
Alabama Power Company 2017 Annual Report

Cautionary Statement Regarding Forward-Looking Statements

The Company's 2017 Annual Report contains forward-looking statements. Forward-looking statements include, among other things, statements concerning regulated rates, customer and sales growth, economic conditions, fuel and environmental cost recovery and other rate actions, current and proposed environmental regulations and related compliance plans and estimated expenditures, pending or potential litigation matters, access to sources of capital, projections for the qualified pension plan, postretirement benefit plans, and nuclear decommissioning trust fund contributions, financing activities, filings with state and federal regulatory authorities, impacts of the Tax Reform Legislation, federal income tax benefits, estimated sales and purchases under power sale and purchase agreements, and estimated construction and other plans and expenditures. In some cases, forward-looking statements can be identified by terminology such as "may," "will," "could," "should," "expects," "plans," "anticipates," "believes," "estimates," "projects," "predicts," "potential," or "continue" or the negative of these terms or other similar terminology. There are various factors that could cause actual results to differ materially from those suggested by the forward-looking statements; accordingly, there can be no assurance that such indicated results will be realized. These factors include:

- the impact of recent and future federal and state regulatory changes, including environmental laws 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 Company is 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 Company;
- 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 Company operates;
- variations in demand for electricity, 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 fuels;
- effects of inflation;
- the ability to control costs and avoid cost overruns during the development and construction of facilities, to construct facilities in accordance with the requirements of permits and licenses, and to satisfy any environmental performance standards;
- investment performance of the Company's employee and retiree benefit plans and nuclear decommissioning trust funds;
- advances in technology;
- state and federal rate regulations and the impact of pending and future rate cases and negotiations, including rate actions relating to fuel and other cost recovery mechanisms;
- the inherent risks involved in operating nuclear generating facilities, including environmental, health, regulatory, natural disaster, terrorism, and financial risks;
- the ability to successfully operate generating, transmission, and distribution facilities and the successful performance of necessary corporate functions;
- internal restructuring or other restructuring options that may be pursued;
- potential business strategies, including acquisitions or dispositions of assets or businesses, which cannot be assured to be completed or beneficial to the Company;
- the ability of counterparties of the Company to make payments as and when due and to perform as required;
- the ability to obtain new short- and long-term contracts with wholesale customers;
-

the direct or indirect effect on the Company's business resulting from cyber intrusion or physical attack and the threat of physical attacks;

- interest rate fluctuations and financial market conditions and the results of financing efforts;
- changes in the Company's credit ratings, including impacts on interest rates, access to capital markets, and collateral requirements;
- the impacts of any sovereign financial issues, including impacts on interest rates, access to capital markets, impacts on foreign currency exchange rates, counterparty performance, and the economy in general;

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- the ability of the Company to obtain additional generating capacity (or sell excess generating capacity) at competitive prices;
- catastrophic events such as fires, earthquakes, explosions, floods, tornadoes, hurricanes and other storms, droughts, pandemic health events such as influenzas, or other similar occurrences;
- the direct or indirect effects on the Company's business resulting from incidents affecting the U.S. electric grid or operation of generating resources;
- the effect of accounting pronouncements issued periodically by standard-setting bodies; and
- other factors discussed elsewhere herein and in other reports filed by the Company from time to time with the SEC.

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

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STATEMENTS OF INCOME
For the Years Ended December 31, 2017, 2016, and 2015
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| | 2017 | 2016 | 2015 |
|---|---|---|---|
| | (in millions) | | |
| Operating Revenues: | | | |
| Retail revenues | $5,458 | $5,322 | $5,234 |
| Wholesale revenues, non-affiliates | 276 | 283 | 241 |
| Wholesale revenues, affiliates | 97 | 69 | 84 |
| Other revenues | 208 | 215 | 209 |
| Total operating revenues | 6,039 | 5,889 | 5,768 |
| Operating Expenses: | | | |
| Fuel | 1,225 | 1,297 | 1,342 |
| Purchased power, non-affiliates | 170 | 166 | 171 |
| Purchased power, affiliates | 158 | 168 | 180 |
| Other operations and maintenance | 1,652 | 1,510 | 1,501 |
| Depreciation and amortization | 736 | 703 | 643 |
| Taxes other than income taxes | 384 | 380 | 368 |
| Total operating expenses | 4,325 | 4,224 | 4,205 |
| Operating Income | 1,714 | 1,665 | 1,563 |
| Other Income and (Expense): | | | |
| Allowance for equity funds used during construction | 39 | 28 | 60 |
| Interest expense, net of amounts capitalized | (305) | (302) | (274) |
| Other income (expense), net | (14) | (21) | (32) |
| Total other income and (expense) | (280) | (295) | (246) |
| Earnings Before Income Taxes | 1,434 | 1,370 | 1,317 |
| Income taxes | 568 | 531 | 506 |
| Net Income | 866 | 839 | 811 |
| Dividends on Preferred and Preference Stock | 18 | 17 | 26 |
| Net Income After Dividends on Preferred and Preference Stock | $848 | $822 | $785 |

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

STATEMENTS OF COMPREHENSIVE INCOME
For the Years Ended December 31, 2017, 2016, and 2015
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| | 2017 | 2016 | 2015 |
|---|---|---|---|
| | (in millions) | | |
| Net Income | $866 | $839 | $811 |
| Other comprehensive income (loss): | | | |
| Qualifying hedges: | | | |
| Changes in fair value, net of tax of $(1), $(1), and $(3), respectively | 1 | (2) | (5) |
| Reclassification adjustment for amounts included in net income, net of tax of $2, $2, and $1, respectively | 3 | 4 | 2 |
| Total other comprehensive income (loss) | 4 | 2 | (3) |
| Comprehensive Income | $870 | $841 | $808 |

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

STATEMENTS OF CASH FLOWS
For the Years Ended December 31, 2017, 2016, and 2015
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| | 2017 | 2016 | 2015 |
|---|---|---|---|
| | (in millions) | | |
| Operating Activities: | | | |
| Net income | $866 | $839 | $811 |
| Adjustments to reconcile net income | | | |
| to net cash provided from operating activities — | | | |
| Depreciation and amortization, total | 888 | 844 | 780 |
| Deferred income taxes | 409 | 407 | 388 |
| Allowance for equity funds used during construction | (39) | (28) | (60) |
| Pension and postretirement funding | (2) | (133) | — |
| Other, net | (14) | (102) | 15 |
| Changes in certain current assets and liabilities — | | | |
| -Receivables | (168) | 94 | (160) |
| -Other current assets | (16) | 1 | 40 |
| -Accounts payable | 71 | 73 | 3 |
| -Accrued taxes | (84) | 93 | 138 |
| -Retail fuel cost over recovery | (76) | (162) | 191 |
| -Other current liabilities | 2 | 23 | (4) |
| Net cash provided from operating activities | 1,837 | 1,949 | 2,142 |
| Investing Activities: | | | |
| Property additions | (1,882) | (1,272) | (1,367) |
| Nuclear decommissioning trust fund purchases | (237) | (352) | (439) |
| Nuclear decommissioning trust fund sales | 237 | 351 | 438 |
| Cost of removal net of salvage | (112) | (94) | (71) |
| Change in construction payables | 161 | (37) | (15) |
| Other investing activities | (43) | (34) | (34) |
| Net cash used for investing activities | (1,876) | (1,438) | (1,488) |
| Financing Activities: | | | |
| Increase in notes payable, net | 3 | — | — |
| Proceeds — | | | |
| Senior notes | 1,100 | 400 | 975 |
| Preferred stock | 250 | — | — |
| Pollution control revenue bonds | — | — | 80 |
| Other long-term debt | — | 45 | — |
| Capital contributions from parent company | 361 | 260 | 22 |
| Redemptions and repurchases — | | | |
| Senior notes | (525) | (200) | (650) |
| Preferred and preference stock | (238) | — | (412) |
| Pollution control revenue bonds | (36) | — | (134) |
| Payment of common stock dividends | (714) | (765) | (571) |
| Other financing activities | (38) | (25) | (43) |
| Net cash provided from (used for) financing activities | 163 | (285) | (733) |
| Net Change in Cash and Cash Equivalents | 124 | 226 | (79) |
| Cash and Cash Equivalents at Beginning of Year | 420 | 194 | 273 |
| Cash and Cash Equivalents at End of Year | $544 | $420 | $194 |
| Supplemental Cash Flow Information: | | | |

| | | | |
|---|---|---|---|
| Cash paid (received) during the period for — | | | |
| Interest (net of $15, $11, and $22 capitalized, respectively) | $285 | $277 | $250 |
| Income taxes (net of refunds) | 236 | (108 ) | 121 |
| Noncash transactions — Accrued property additions at year-end | 245 | 84 | 121 |

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

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BALANCE SHEETS
At December 31, 2017 and 2016
Alabama Power Company 2017 Annual Report

| Assets | 2017 | 2016 |
|---|---|---|
| | (in millions) | |
| Current Assets: | | |
| Cash and cash equivalents | $544 | $420 |
| Receivables — | | |
| Customer accounts receivable | 355 | 348 |
| Unbilled revenues | 162 | 146 |
| Affiliated | 43 | 40 |
| Other accounts and notes receivable | 55 | 27 |
| Accumulated provision for uncollectible accounts | (9) | (10) |
| Fossil fuel stock | 184 | 205 |
| Materials and supplies | 458 | 435 |
| Other regulatory assets, current | 124 | 149 |
| Other current assets | 90 | 45 |
| Total current assets | 2,006 | 1,805 |
| Property, Plant, and Equipment: | | |
| In service | 27,326 | 26,031 |
| Less: Accumulated provision for depreciation | 9,563 | 9,112 |
| Plant in service, net of depreciation | 17,763 | 16,919 |
| Nuclear fuel, at amortized cost | 339 | 336 |
| Construction work in progress | 908 | 491 |
| Total property, plant, and equipment | 19,010 | 17,746 |
| Other Property and Investments: | | |
| Equity investments in unconsolidated subsidiaries | 67 | 66 |
| Nuclear decommissioning trusts, at fair value | 903 | 792 |
| Miscellaneous property and investments | 124 | 112 |
| Total other property and investments | 1,094 | 970 |
| Deferred Charges and Other Assets: | | |
| Deferred charges related to income taxes | 239 | 525 |
| Deferred under recovered regulatory clause revenues | 54 | 150 |
| Other regulatory assets, deferred | 1,272 | 1,157 |
| Other deferred charges and assets | 189 | 163 |
| Total deferred charges and other assets | 1,754 | 1,995 |
| Total Assets | $23,864 | $22,516 |

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

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BALANCE SHEETS
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| Liabilities and Stockholder's Equity | 2017 | 2016 |
|---|---|---|
| | (in millions) | |
| Current Liabilities: | | |
| Securities due within one year | $— | $561 |
| Accounts payable — | | |
| Affiliated | 327 | 297 |
| Other | 585 | 433 |
| Customer deposits | 92 | 88 |
| Accrued taxes — | | |
| Accrued income taxes | 9 | 45 |
| Other accrued taxes | 45 | 42 |
| Accrued interest | 77 | 78 |
| Accrued compensation | 205 | 193 |
| Other regulatory liabilities, current | 1 | 85 |
| Other current liabilities | 59 | 76 |
| Total current liabilities | 1,400 | 1,898 |
| Long-Term Debt (See accompanying statements) | 7,628 | 6,535 |
| Deferred Credits and Other Liabilities: | | |
| Accumulated deferred income taxes | 2,760 | 4,654 |
| Deferred credits related to income taxes | 2,082 | 65 |
| Accumulated deferred ITCs | 112 | 110 |
| Employee benefit obligations | 304 | 300 |
| Asset retirement obligations | 1,702 | 1,503 |
| Other cost of removal obligations | 609 | 684 |
| Other regulatory liabilities, deferred | 84 | 100 |
| Other deferred credits and liabilities | 63 | 63 |
| Total deferred credits and other liabilities | 7,716 | 7,479 |
| Total Liabilities | 16,744 | 15,912 |
| Redeemable Preferred Stock (See accompanying statements) | 291 | 85 |
| Preference Stock (See accompanying statements) | — | 196 |
| Common Stockholder's Equity (See accompanying statements) | 6,829 | 6,323 |
| Total Liabilities and Stockholder's Equity | $23,864 | $22,516 |
| Commitments and Contingent Matters (See notes) | | |

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

STATEMENTS OF CAPITALIZATION
At December 31, 2017 and 2016
Alabama Power Company 2017 Annual Report

| | 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 notes payable — | | | | |
| 5.50% to 5.55% due 2017 | — | 525 | | |
| 5.125% due 2019 | 200 | 200 | | |
| 3.375% due 2020 | 250 | 250 | | |
| 2.38% to 3.95% due 2021 | 220 | 220 | | |
| 2.45% to 5.875% due 2022 | 750 | 200 | | |
| 2.80% to 6.125% due 2023-2047 | 4,975 | 4,425 | | |
| Variable rates (2.55% to 2.786% at 12/31/17) due 2021 | 25 | 25 | | |
| Total long-term notes payable | 6,420 | 5,845 | | |
| Other long-term debt — | | | | |
| Pollution control revenue bonds — | | | | |
| 1.625% to 1.85% due 2034 | 207 | 207 | | |
| Variable rates (0.77% to 0.79% at 1/1/17) due 2017 | — | 36 | | |
| Variable rates (1.86% to 1.87% at 12/31/17) due 2021 | 65 | 65 | | |
| Variable rates (1.70% to 1.87% at 12/31/17) due 2024-2038 | 788 | 788 | | |
| Total other long-term debt | 1,060 | 1,096 | | |
| Capitalized lease obligations | 4 | 4 | | |
| Unamortized debt premium (discount), net | (11) | (9) | | |
| Unamortized debt issuance expense | (51) | (46) | | |
| Total long-term debt (annual interest requirement — $305 million) | 7,628 | 7,096 | | |
| Less amount due within one year | — | 561 | | |
| Long-term debt excluding amount due within one year | 7,628 | 6,535 | 51.7 % | 49.7 % |
| Redeemable Preferred Stock: | | | | |
| Cumulative redeemable preferred stock | | | | |
| $100 par or stated value — 4.20% to 4.92% | | | | |
| Authorized — 3,850,000 shares | | | | |
| Outstanding — 475,115 shares | 48 | 48 | | |
| $1 par value — | | | | |
| Authorized — 27,500,000 shares | | | | |
| Outstanding — 2017: 5.00% — 10,000,000 shares: $25 stated value | | | | |
| — 2016: 5.83% — 1,520,000 shares: $25 stated value | | | | |
| (annual dividend requirement — $15 million) | 243 | 37 | | |
| Total redeemable preferred stock | 291 | 85 | 2.0 | 0.7 |
| Preference Stock: | | | | |
| $1 par value — 6.45% to 6.50% | | | | |
| Authorized — 40,000,000 shares | | | | |
| Outstanding — 2017: no shares | | | | |
| — 2016: 8,000,000 shares (non-cumulative): $25 stated value | — | 196 | — | 1.5 |
| Common Stockholder's Equity: | | | | |
| Common stock, par value $40 per share — | | | | |

| | | | | |
|---|---|---|---|---|
| Authorized — 40,000,000 shares | | | | |
| Outstanding — 30,537,500 shares | 1,222 | 1,222 | | |
| Paid-in capital | 2,986 | 2,613 | | |
| Retained earnings | 2,647 | 2,518 | | |
| Accumulated other comprehensive loss | (26 ) | (30 ) | | |
| Total common stockholder's equity | 6,829 | 6,323 | 46.3 | 48.1 |
| Total Capitalization | $14,748 | $13,139 | 100.0% | 100.0% |

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

STATEMENTS OF COMMON STOCKHOLDER'S EQUITY
For the Years Ended December 31, 2017, 2016, and 2015
Alabama Power Company 2017 Annual Report

| | Number of Common Shares Issued | Common Stock | Paid-In Capital | Retained Earnings | Accumulated Other Comprehensive Income (Loss) | Total |
|---|---|---|---|---|---|---|
| | (in millions) | | | | | |
| Balance at December 31, 2014 | 31 | $ 1,222 | $2,304 | $2,255 | $ (29) | $5,752 |
| Net income after dividends on preferred and preference stock | — | — | — | 785 | — | 785 |
| Capital contributions from parent company | — | — | 37 | — | — | 37 |
| Other comprehensive income (loss) | — | — | — | — | (3) | (3) |
| Cash dividends on common stock | — | — | — | (571) | — | (571) |
| Other | — | — | — | (8) | — | (8) |
| Balance at December 31, 2015 | 31 | 1,222 | 2,341 | 2,461 | (32) | 5,992 |
| Net income after dividends on preferred and preference stock | — | — | — | 822 | — | 822 |
| Capital contributions from parent company | — | — | 272 | — | — | 272 |
| Other comprehensive income (loss) | — | — | — | — | 2 | 2 |
| Cash dividends on common stock | — | — | — | (765) | — | (765) |
| Balance at December 31, 2016 | 31 | 1,222 | 2,613 | 2,518 | (30) | 6,323 |
| Net income after dividends on preferred and preference stock | — | — | — | 848 | — | 848 |
| Capital contributions from parent company | — | — | 373 | — | — | 373 |
| Other comprehensive income (loss) | — | — | — | — | 4 | 4 |
| Cash dividends on common stock | — | — | — | (714) | — | (714) |
| Other | — | — | — | (5) | — | (5) |
| Balance at December 31, 2017 | 31 | $ 1,222 | $2,986 | $2,647 | $ (26) | $6,829 |

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

NOTES TO FINANCIAL STATEMENTS
Alabama Power Company 2017 Annual Report

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NOTES (continued)
Alabama Power Company 2017 Annual Report

1. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES
General
Alabama Power Company (the Company) is a wholly-owned subsidiary of Southern Company, which is the parent company of the Company and three other traditional electric operating companies, Southern Power, Southern Company Gas (as of July 1, 2016), SCS, Southern Linc, Southern Company Holdings, Inc. (Southern Holdings), Southern Nuclear, PowerSecure, Inc. (PowerSecure) (as of May 9, 2016), and other direct and indirect subsidiaries. The traditional electric operating companies – the Company, Georgia Power, Gulf Power, and Mississippi Power – are vertically integrated utilities providing electric service in four Southeastern states. The Company provides electric service to retail and wholesale customers within its traditional service territory located in the State of Alabama in addition to wholesale customers in the Southeast. Southern Power 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 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, including the Company's Plant Farley. PowerSecure is a provider of products and services in the areas of distributed generation, energy efficiency, and utility infrastructure.
The equity method is used for subsidiaries in which the Company has significant influence but does not control and for variable interest entities (VIEs) where the Company has an equity investment, but is not the primary beneficiary.
The Company is subject to regulation by the FERC and the Alabama PSC. As such, the Company's financial statements reflect the effects of rate regulation in accordance with GAAP and comply with the accounting policies and practices prescribed by its regulatory commissions. The preparation of financial statements in conformity with GAAP requires the use of estimates, and the actual results may differ from those estimates. Certain prior years' data presented in the financial statements have been reclassified to conform to the current year presentation.
Recently Issued Accounting Standards
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 the Company's revenue, including energy provided to customers, is from tariff offerings that provide electricity without a defined contractual term, as well as longer-term contractual commitments, including PPAs.
The 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 energy-related derivatives, are excluded from the scope of ASC 606 and, therefore, will be accounted for and disclosed separately from revenues under ASC 606. The 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. The Company applied the modified retrospective method of adoption effective January 1, 2018. The 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.

NOTES (continued)
Alabama Power Company 2017 Annual Report

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. ASU 2016-02 is effective for fiscal years beginning after December 15, 2018 and the Company will adopt the new standard effective January 1, 2019.
The 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, the 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, railcars, and a PPA where the Company is the lessee and outdoor lighting and to land where the Company is the lessor. The Company is currently analyzing pole attachment agreements and a lease determination has not been made at this time. While the Company has not yet determined the ultimate impact, adoption of ASU 2016-02 is expected to have a significant impact on the 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, the Company recognized any excess tax benefits and deficiencies related to the exercise and vesting of stock compensation as additional paid-in capital. In addition, the new guidance requires excess tax benefits for share-based payments to be included in net cash provided from operating activities rather than net cash provided from financing activities on the statement of cash flows. The Company elected to adopt the guidance in 2016 and reflect the related adjustments as of January 1, 2016. Prior year's data presented in the financial statements has not been adjusted. The Company also elected to recognize forfeitures as they occur. The new guidance did not have a material impact on the results of operations, financial position, or cash flows of the Company. See Notes 5 and 8 for disclosures impacted by ASU 2016-09.
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 the 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. The 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. The Company adopted ASU 2017-12 effective January 1, 2018 with no material impact on its financial statements.

Affiliate Transactions

The Company has an agreement with SCS under which the following services are rendered to the Company at direct or allocated cost: general and design engineering, operations, purchasing, accounting, finance and treasury, tax, information technology, marketing, auditing, insurance and pension administration, human resources, systems and procedures, digital wireless communications, and other services with respect to business and operations, construction management, and power pool transactions. Costs for these services amounted to $479 million, $460 million, and $438 million during 2017, 2016, and 2015, respectively. Cost allocation methodologies used by SCS prior to the repeal of the Public Utility Holding Company Act of 1935, as amended, were approved by the SEC. Subsequently, additional cost allocation methodologies have been reported to the FERC and management believes they are reasonable. The FERC permits services to be rendered at cost by system service companies. See Note 7 under "Operating Leases" for information on leases of cellular tower space for the Company's digital wireless communications equipment.

The Company has an agreement with Southern Nuclear under which the following nuclear-related services are rendered to the Company at cost: general executive and advisory services, general operations, management and technical services, administrative services including procurement, accounting, employee relations, systems and procedures services, strategic planning and budgeting services, and other services with respect to business and operations. Costs for these services amounted to $248 million, $249 million, and $243 million during 2017, 2016, and 2015, respectively.

The Company jointly owns Plant Greene County with Mississippi Power. The Company has an agreement with Mississippi Power under which the Company operates Plant Greene County, and Mississippi Power reimburses the Company for its proportionate share of non-fuel expenses, which totaled $9 million in 2017, $13 million in 2016, and $11 million in 2015. Mississippi Power also reimbursed the Company for any direct fuel purchases delivered from one of the Company's transfer facilities. There were no such fuel purchases in 2017 and 2016 and $8 million in 2015. See Note 4 for additional information.

The Company has an agreement with Gulf Power under which the Company made transmission system upgrades to ensure firm delivery of energy under a non-affiliate PPA from a combined cycle plant located in Autauga County, Alabama. Under a related tariff, the Company received $11 million in 2017, $12 million in 2016, and $14 million in 2015 and expects to recover a total of approximately $61 million from 2018 through 2023 from Gulf Power.

In September 2016, Southern Company Gas acquired a 50% equity interest in Southern Natural Gas Company, L.L.C. (SNG). Prior to completion of the acquisition, SCS, as agent for the Company, had entered into a long-term interstate natural gas transportation agreement with SNG. The interstate transportation service provided to the Company by SNG pursuant to this agreement is governed by the terms and conditions of SNG's natural gas tariff and is subject to FERC regulation. Transportation costs under this agreement were approximately $9 million in 2017 and $2 million for the period subsequent to Southern Company Gas' investment in SNG through December 31, 2016.

The Company has agreements with PowerSecure for services related to utility infrastructure construction, distributed energy, and energy efficiency projects. Costs for these services amounted to approximately $11 million for 2017 and were immaterial for 2016.

The Company provides incidental services to and receives such services from other Southern Company subsidiaries which are generally minor in duration and amount. Except as described herein, the Company neither provided nor received any material services to or from affiliates in 2017, 2016, or 2015.

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

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

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Regulatory Assets and Liabilities

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

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

| | 2017 | 2016 | Note |
|---|---|---|---|
| | (in millions) | | |
| Retiree benefit plans | $946 | $947 | (i,j) |
| Deferred income tax charges | 240 | 526 | (a,k,n) |
| Regulatory clauses | 142 | — | (m) |
| Vacation pay | 70 | 69 | (c,j) |
| Loss on reacquired debt | 62 | 68 | (b) |
| Nuclear outage | 56 | 70 | (d) |
| Remaining net book value of retired assets | 54 | 69 | (l) |
| Under/(over) recovered regulatory clause revenues | 53 | 76 | (d) |
| Other regulatory assets | 51 | 50 | (f) |
| Fuel-hedging losses | 7 | 1 | (e,j) |
| Deferred income tax credits | (2,082) | (65) | (a,n) |
| Other cost of removal obligations | (609) | (684) | (a) |
| Natural disaster reserve | (38) | (69) | (h) |
| Asset retirement obligations | (33) | 12 | (a) |
| Other regulatory liabilities | (7) | (23) | (e,g) |
| Total regulatory assets (liabilities), net | $(1,088) | $1,047 | |

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

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

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

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

(d) Recorded and recovered or amortized as approved or accepted by the Alabama PSC over periods not exceeding 10 years. See Note 3 under "Retail Regulatory Matters" for additional information.

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

(f) Comprised of components including generation site selection/evaluation costs, PPA capacity (to be recovered over the next 12 months), and other miscellaneous assets. Recorded as accepted by the Alabama PSC. Capitalized upon initialization of related construction projects, if applicable.

(g) Comprised of components including mine reclamation and remediation liabilities and fuel-hedging gains. Recorded as accepted by the Alabama PSC. Mine reclamation and remediation liabilities will be settled following completion of the related activities.

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

(i)

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

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

(k) Included in the deferred income tax charges are $13 million for 2017 and $16 million for 2016 for the retiree Medicare drug subsidy, which is recovered and amortized, as approved by the Alabama PSC, over the average remaining service period which may range up to 15 years.

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

(m) Established per an order from the Alabama PSC issued on February 17, 2017 and will be amortized concurrently with the effective date of the Company's next depreciation study. See Note 3 under "Retail Regulatory Matters – Rate RSE" for additional information.

(n) 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 established consistent with guidance provided by the Alabama PSC. See Note 5 for additional information.

In the event that a portion of the Company's operations is no longer subject to applicable accounting rules for rate regulation, the Company would be required to write off to income or reclassify to accumulated OCI related regulatory assets and liabilities that are not specifically recoverable through regulated rates. In addition, the Company would be required to determine if any impairment to other assets, including plant, exists and write down the assets, if impaired, to their fair values. All regulatory assets and liabilities are to be reflected in rates. See Note 3 under "Retail Regulatory Matters" for additional information.

Revenues

Wholesale capacity revenues from PPAs are recognized either on a levelized basis over the appropriate contract period or the amount billable under the contract terms. Energy and other revenues are recognized as services are provided. Unbilled revenues related to retail sales are accrued at the end of each fiscal period. Electric rates for the Company include provisions to adjust billings for fluctuations in fuel costs, fuel hedging, the energy component of purchased power costs, and certain other costs. Revenues are adjusted for differences between these actual costs and amounts billed in current regulated rates. Under or over recovered regulatory clause revenues are recorded in the balance sheets and are recovered or returned to customers through adjustments to the billing factors. The Company and the Alabama PSC continuously monitor the under/over recovered balances. The Company files for revised rates as required or when management deems appropriate, depending on the rate. See Note 3 under "Retail Regulatory Matters – Rate ECR" and "Retail Regulatory Matters – Rate CNP Compliance" for additional information.

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

Fuel Costs

Fuel costs are expensed as the fuel is used. Fuel expense generally includes fuel transportation costs and the cost of purchased emissions allowances as they are used. Fuel expense also includes the amortization of the cost of nuclear fuel.

Income and Other Taxes

The Company uses the liability method of accounting for deferred income taxes and provides deferred income taxes for all significant income tax temporary differences. Federal ITCs utilized are deferred and amortized to income over the average life of the related property. Taxes that are collected from customers on behalf of governmental agencies to be remitted to these agencies are presented net on the statements of income.

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

Property, Plant, and Equipment

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

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

| | 2017 | 2016 |
|---|---|---|
| | (in millions) | |
| Generation | $14,213 | $13,551 |
| Transmission | 4,119 | 3,921 |
| Distribution | 7,034 | 6,707 |
| General | 1,948 | 1,840 |
| Plant acquisition adjustment | 12 | 12 |
| Total plant in service | $27,326 | $26,031 |

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

Nuclear Outage Accounting Order
In accordance with an Alabama PSC order, nuclear outage operations and maintenance expenses for the two units at Plant Farley are deferred to a regulatory asset when the charges actually occur and are then amortized over a subsequent 18-month period with

the fall outage costs amortization beginning in January of the following year and the spring outage costs amortization beginning in July of the same year.

Depreciation and Amortization

Depreciation of the original cost of utility plant in service is provided primarily by using composite straight-line rates, which approximated 2.9% in 2017, 3% in 2016, and 2.9% in 2015. Depreciation studies are conducted periodically to update the composite rates and the information is provided to the Alabama PSC and approved by the FERC. When property subject to composite depreciation is retired or otherwise disposed of in the normal course of business, its original cost, together with the cost of removal, less salvage, is charged to accumulated depreciation. For other property dispositions, the applicable cost and accumulated depreciation are removed from the balance sheet accounts, and a gain or loss is recognized. Minor items of property included in the original cost of the plant are retired when the related property unit is retired.

In 2016, the Company submitted an updated depreciation study to the FERC and received authorization to use the recommended rates beginning January 2017. The study was also provided to the Alabama PSC.

Asset Retirement Obligations and Other Costs of Removal

AROs are computed as the present value of the estimated ultimate costs for an asset's future retirement and are recorded in the period in which the liability is incurred. The costs are capitalized as part of the related long-lived asset and depreciated over the asset's useful life. In the absence of quoted market prices, AROs are estimated using present value techniques in which estimates of future cash outlays associated with the asset retirements are discounted using a credit-adjusted risk-free rate. Estimates of the timing and amounts of future cash outlays are based on projections of when and how the assets will be retired and the cost of future removal activities. The Company has received accounting guidance from the Alabama PSC allowing the continued accrual of other future retirement costs for long-lived assets that the Company does not have a legal obligation to retire. Accordingly, the accumulated removal costs for these obligations are reflected in the balance sheets as a regulatory liability.

The liability for AROs primarily relates to the decommissioning of the Company's nuclear facility, Plant Farley, and facilities that are subject to the Disposal of Coal Combustion Residuals from Electric Utilities final rule published by the EPA in 2015 (CCR Rule), principally ash ponds. In addition, the Company has retirement obligations related to various landfill sites, underground storage tanks, asbestos removal related to ongoing repair and maintenance, disposal of polychlorinated biphenyls in certain transformers, and disposal of sulfur hexafluoride gas in certain substation breakers. The Company also has identified retirement obligations related to certain transmission and distribution facilities, asbestos containing material within long-term assets not subject to ongoing repair and maintenance activities, and certain wireless communication towers. However, liabilities for the removal of these assets have not been recorded because the settlement timing for the retirement obligations related to these assets is indeterminable and, therefore, the fair value of the retirement obligations cannot be reasonably estimated. A liability for these AROs will be recognized when sufficient information becomes available to support a reasonable estimation of the ARO. The Company will continue to recognize in the statements of income allowed removal costs in accordance with its regulatory treatment. Any differences between costs recognized in accordance with accounting standards related to asset retirement and environmental obligations and those reflected in rates are recognized as either a regulatory asset or liability, as ordered by the Alabama PSC, and are reflected in the balance sheets. See "Nuclear Decommissioning" herein for additional information on amounts included in rates.

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

| | 2017 | 2016 |
|---|---|---|
| | (in millions) | |
| Balance at beginning of year | $1,533 | $1,448 |
| Liabilities incurred | — | 5 |
| Liabilities settled | (26) | (25) |
| Accretion | 77 | 73 |

| | | |
|---|---|---|
| Cash flow revisions | 125 | 32 |
| Balance at end of year | $1,709 | $1,533 |

The increase in liabilities incurred and cash flow revisions in 2017 is primarily due to updated cost estimates related to the closure of ash ponds and landfills. The increase in 2016 is primarily related to changes in ash pond closure strategy.

The cost estimates for AROs related to the CCR Rule are based on information as of December 31, 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 in place. As further analysis is performed and closure details are developed, the Company 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. The Company has external trust funds (Funds) to comply with the NRC's regulations. Use of the Funds is restricted to nuclear decommissioning activities. The Funds are managed and invested in accordance with applicable requirements of various regulatory bodies, including the NRC, the FERC, and the Alabama PSC, as well as the IRS. While the Company is allowed to prescribe an overall investment policy to the Funds' managers, the Company and its affiliates are not allowed to engage in the day-to-day management of the Funds or to mandate individual investment decisions. Day-to-day management of the investments in the Funds is delegated to unrelated third party managers with oversight by the management of the Company. The Funds' managers are authorized, within certain investment guidelines, to actively buy and sell securities at their own discretion in order to maximize the return on the Funds' investments. The Funds are invested in a tax-efficient manner in a diversified mix of equity and fixed income securities and are reported as trading securities.

The Company records the investment securities held in the Funds at fair value, as disclosed in Note 10, as management believes that fair value best represents the nature of the Funds. Gains and losses, whether realized or unrealized, are recorded in the regulatory liability for AROs in the balance sheets and are not included in net income or OCI. Fair value adjustments and realized gains and losses are determined on a specific identification basis.

At December 31, 2017, investment securities in the Funds totaled $902 million, consisting of equity securities of $644 million, debt securities of $223 million, and $35 million of other securities. At December 31, 2016, investment securities in the Funds totaled $790 million, consisting of equity securities of $552 million, debt securities of $208 million, and $30 million of other securities. These amounts exclude receivables related to investment income and pending investment sales and payables related to pending investment purchases.

Sales of the securities held in the Funds resulted in cash proceeds of $237 million, $351 million, and $438 million 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 $125 million, which included $98 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 $76 million, which included $34 million related to unrealized gains on securities held in the Funds at December 31, 2016. For 2015, fair value increases, including reinvested interest and dividends and excluding the Funds' expenses, were $8 million, which included $57 million related to unrealized losses on securities held in the Funds at December 31, 2015. While the investment securities held in the Funds are reported as trading securities, the Funds continue to be managed with a long-term focus. Accordingly, all purchases and sales within the Funds are presented separately in the statements of cash flows as investing cash flows, consistent with the nature of the securities and purpose for which the securities were acquired.

Amounts previously recorded in internal reserves are being transferred into the Funds through 2040 as approved by the Alabama PSC. The NRC's minimum external funding requirements are based on a generic estimate of the cost to decommission only the radioactive portions of a nuclear unit based on the size and type of reactor. The Company has filed a plan with the NRC designed to ensure that, over time, the deposits and earnings of the Funds will provide the minimum funding amounts prescribed by the NRC.

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

| | 2017 | 2016 |
|---|---|---|
| | (in millions) | |
| External trust funds | $902 | $790 |

| | | |
|---|---|---|
| Internal reserves | 18 | 19 |
| Total | $ 920 | $ 809 |

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Site study cost is the estimate to decommission a facility as of the site study year. The estimated costs of decommissioning as of December 31, 2017 based on the most current study performed in 2013 for Plant Farley are as follows:

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

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

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

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

Allowance for Funds Used During Construction

The Company records AFUDC, which represents the estimated debt and equity costs of capital funds that are necessary to finance the construction of new regulated facilities. While cash is not realized currently, AFUDC increases the revenue requirement and is recovered over the service life of the plant through a higher rate base and higher depreciation. The equity component of AFUDC is not included in calculating taxable income. All current construction costs are included in retail rates. The AFUDC composite rate as of December 31 was 8.3% in 2017, 8.4% in 2016, and 8.7% in 2015. AFUDC, net of income taxes, as a percentage of net income after dividends on preferred and preference stock was 5.7% in 2017, 4.2% in 2016, and 9.3% in 2015.

Impairment of Long-Lived Assets and Intangibles

The Company evaluates long-lived assets for impairment when events or changes in circumstances indicate that the carrying value of such assets may not be recoverable. The determination of whether an impairment has occurred is based on either a specific regulatory disallowance or an estimate of undiscounted future cash flows attributable to the assets, as compared with the carrying value of the assets. If an impairment has occurred, the amount of the impairment recognized is determined by either the amount of regulatory disallowance or by estimating the fair value of the assets and recording a loss if the carrying value is greater than the fair value. For assets identified as held for sale, the carrying value is compared to the estimated fair value less the cost to sell in order to determine if an impairment loss is required. Until the assets are disposed of, their estimated fair value is re-evaluated when circumstances or events change.

Cash and Cash Equivalents

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

Materials and Supplies

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

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Fuel Inventory

Fuel inventory includes the average cost of coal, natural gas, oil, transportation, and emissions allowances. Fuel is recorded to inventory when purchased and then expensed, at weighted average cost, as used and recovered by the Company through energy cost recovery rates approved by the Alabama PSC. Emissions allowances granted by the EPA are included in inventory at zero cost.

Financial Instruments

The Company uses derivative financial instruments to limit exposure to fluctuations in interest rates, the prices of certain fuel purchases, and electricity purchases and sales. All derivative financial instruments are recognized as either assets or liabilities on the balance sheets (included in "Other") and are measured at fair value. See Note 10 for additional information regarding fair value. Substantially all of the Company's bulk energy purchases and sales contracts that meet the definition of a derivative are excluded from fair value accounting requirements because they qualify for the "normal" scope exception, and are accounted for under the accrual method. Derivative contracts that qualify as cash flow hedges of anticipated transactions or are recoverable through the Alabama PSC-approved fuel-hedging program result in the deferral of related gains and losses in OCI or regulatory assets and liabilities, respectively, until the hedged transactions occur. Any ineffectiveness arising from cash flow hedges is recognized currently in net income. Other derivative contracts that qualify as fair value hedges are marked to market through current period income and are recorded on a net basis in the statements of income. Cash flows from derivatives are classified on the statement of cash flows in the same category as the hedged item. See Note 11 for additional information regarding derivatives.

The Company offsets fair value amounts recognized for multiple derivative instruments executed with the same counterparty under a netting arrangement. Additionally, the Company had no outstanding collateral repayment obligations or rights to reclaim collateral arising from derivative instruments recognized at December 31, 2017.

The 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 reclassifications for amounts included in net income.

Variable Interest Entities

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

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

2. RETIREMENT BENEFITS

The Company has a defined benefit, trusteed, pension plan covering substantially all employees. This qualified pension plan is funded in accordance with requirements of the Employee Retirement Income Security Act of 1974, as amended (ERISA). No contributions to the qualified pension plan were made for the year ended December 31, 2017 and no mandatory contributions to the qualified pension plan are anticipated for the year ending December 31, 2018. The Company also provides certain defined benefit pension plans for a selected group of management and highly compensated employees. Benefits under these non-qualified pension plans are funded on a cash basis. In addition, the Company provides certain medical care and life insurance benefits for retired employees through other postretirement benefit plans. The Company funds its other postretirement trusts to the extent required by the Alabama PSC and the FERC. For the year ending December 31, 2018, no other postretirement trusts contributions are expected.

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Actuarial Assumptions

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

| Assumptions used to determine net periodic costs: | 2017 | 2016 | 2015 |
|---|---|---|---|
| Pension plans | | | |
| Discount rate – benefit obligations | 4.44% | 4.67% | 4.18% |
| Discount rate – interest costs | 3.76 | 3.90 | 4.18 |
| Discount rate – service costs | 4.85 | 5.07 | 4.49 |
| Expected long-term return on plan assets | 7.95 | 8.20 | 8.20 |
| Annual salary increase | 4.46 | 4.46 | 3.59 |
| Other postretirement benefit plans | | | |
| Discount rate – benefit obligations | 4.27% | 4.51% | 4.04% |
| Discount rate – interest costs | 3.58 | 3.69 | 4.04 |
| Discount rate – service costs | 4.70 | 4.96 | 4.40 |
| Expected long-term return on plan assets | 6.83 | 6.83 | 7.17 |
| Annual salary increase | 4.46 | 4.46 | 3.59 |

| Assumptions used to determine benefit obligations: | 2017 | 2016 |
|---|---|---|
| Pension plans | | |
| Discount rate | 3.81% | 4.44% |
| Annual salary increase | 4.46 | 4.46 |
| Other postretirement benefit plans | | |
| Discount rate | 3.71% | 4.27% |
| Annual salary increase | 4.46 | 4.46 |

The Company estimates the expected rate of return on pension plan and other postretirement benefit plan assets using a financial model to project the expected return on each current investment portfolio. The analysis projects an expected rate of return on each of 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 |

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An annual increase or decrease in the assumed medical care cost trend rate of 1% would affect the APBO and the service and interest cost components at December 31, 2017 as follows:

| | 1 Percent Increase | 1 Percent Decrease |
|---|---|---|
| | (in millions) | |
| Benefit obligation | $30 | $ 26 |
| Service and interest costs | 1 | 1 |

Pension Plans

The total accumulated benefit obligation for the pension plans was $2.7 billion at December 31, 2017 and $2.4 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:

| | 2017 | 2016 |
|---|---|---|
| | (in millions) | |
| Change in benefit obligation | | |
| Benefit obligation at beginning of year | $2,663 | $2,506 |
| Service cost | 63 | 57 |
| Interest cost | 98 | 95 |
| Benefits paid | (120 ) | (109 ) |
| Actuarial (gain) loss | 294 | 114 |
| Balance at end of year | 2,998 | 2,663 |
| Change in plan assets | | |
| Fair value of plan assets at beginning of year | 2,517 | 2,279 |
| Actual return (loss) on plan assets | 427 | 206 |
| Employer contributions | 12 | 141 |
| Benefits paid | (120 ) | (109 ) |
| Fair value of plan assets at end of year | 2,836 | 2,517 |
| Accrued liability | $(162 ) | $(146 ) |

At December 31, 2017, the projected benefit obligations for the qualified and non-qualified pension plans were $2.9 billion and $126 million, respectively. All pension plan assets are related to the qualified pension plan.

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

| | 2017 | 2016 |
|---|---|---|
| | (in millions) | |
| Other regulatory assets, deferred | $890 | $870 |
| Other current liabilities | (12 ) | (12 ) |
| Employee benefit obligations | (150 ) | (134 ) |

Presented below are the amounts included in 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.

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| | 2017 | 2016 | Estimated Amortization in 2018 |
|---|---|---|---|
| | (in millions) | | |
| Prior service cost | $8 | $10 | $ 1 |
| Net (gain) loss | 882 | 860 | 54 |
| Regulatory assets | $890 | $870 | |

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:

| | 2017 | 2016 |
|---|---|---|
| | (in millions) | |
| Regulatory assets: | | |
| Beginning balance | $870 | $822 |
| Net (gain) loss | 64 | 84 |
| Change in prior service costs | — | 7 |
| Reclassification adjustments: | | |
| Amortization of prior service costs | (2) | (3) |
| Amortization of net gain (loss) | (42) | (40) |
| Total reclassification adjustments | (44) | (43) |
| Total change | 20 | 48 |
| Ending balance | $890 | $870 |

Components of net periodic pension cost were as follows:

| | 2017 | 2016 | 2015 |
|---|---|---|---|
| | (in millions) | | |
| Service cost | $63 | $57 | $59 |
| Interest cost | 98 | 95 | 106 |
| Expected return on plan assets | (196) | (184) | (178) |
| Recognized net (gain) loss | 42 | 40 | 55 |
| Net amortization | 2 | 3 | 6 |
| Net periodic pension cost | $9 | $11 | $48 |

Net periodic pension cost is the sum of service cost, interest cost, and other costs netted against the expected return on plan assets. The expected return on plan assets is determined by multiplying the expected rate of return on plan assets and the market-related value of plan assets. In determining the market-related value of plan assets, the Company has elected to amortize changes in the market value of all plan assets over five years rather than recognize the changes immediately. As a result, the accounting value of plan assets that is used to calculate the expected return on plan assets differs from the current fair value of the plan assets.

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Future benefit payments reflect expected future service and are estimated based on assumptions used to measure the projected benefit obligation for the pension plans. At December 31, 2017, estimated benefit payments were as follows:

| | Benefit Payments (in millions) |
|---|---|
| 2018 | $ 129 |
| 2019 | 134 |
| 2020 | 139 |
| 2021 | 143 |
| 2022 | 148 |
| 2023 to 2027 | 807 |

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:

| | 2017 | 2016 |
|---|---|---|
| | (in millions) | |
| Change in benefit obligation | | |
| Benefit obligation at beginning of year | $501 | $505 |
| Service cost | 6 | 5 |
| Interest cost | 17 | 18 |
| Benefits paid | (29) | (28) |
| Actuarial (gain) loss | 20 | (1) |
| Retiree drug subsidy | 2 | 2 |
| Balance at end of year | 517 | 501 |
| Change in plan assets | | |
| Fair value of plan assets at beginning of year | 367 | 363 |
| Actual return (loss) on plan assets | 60 | 23 |
| Employer contributions | 6 | 7 |
| Benefits paid | (27) | (26) |
| Fair value of plan assets at end of year | 406 | 367 |
| Accrued liability | $(111) | $(134) |

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:

| | 2017 | 2016 |
|---|---|---|
| | (in millions) | |
| Other regulatory assets, deferred | $63 | $86 |
| Other regulatory liabilities, deferred | (7) | (10) |
| Employee benefit obligations | (111) | (134) |

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Presented below are the amounts included in 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.

| | 2017 | 2016 | Estimated Amortization in 2018 |
|---|---|---|---|
| | (in millions) | | |
| Prior service cost | $11 | $ 15 | $ 4 |
| Net (gain) loss | 45 | 61 | 1 |
| Net regulatory assets | $56 | $ 76 | |

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:

| | 2017 | 2016 |
|---|---|---|
| | (in millions) | |
| Net regulatory assets (liabilities): | | |
| Beginning balance | $76 | $82 |
| Net (gain) loss | (15 ) | — |
| Reclassification adjustments: | | |
| Amortization of prior service costs | (4 ) | (4 ) |
| Amortization of net gain (loss) | (1 ) | (2 ) |
| Total reclassification adjustments | (5 ) | (6 ) |
| Total change | (20 ) | (6 ) |
| Ending balance | $56 | $76 |

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

| | 2017 | 2016 | 2015 |
|---|---|---|---|
| | (in millions) | | |
| Service cost | $6 | $ 5 | $ 6 |
| Interest cost | 17 | 18 | 20 |
| Expected return on plan assets | (25) | (25 ) | (26 ) |
| Net amortization | 5 | 6 | 5 |
| Net periodic postretirement benefit cost | $3 | $ 4 | $ 5 |

Future benefit payments, including prescription drug benefits, reflect expected future service and are estimated based on assumptions used to measure the APBO for the other postretirement benefit plans. Estimated benefit payments are reduced by drug subsidy receipts expected as a result of the Medicare Prescription Drug, Improvement, and Modernization Act of 2003 as follows:

| | Benefit Payments | Subsidy Receipts | Total |
|---|---|---|---|
| | (in millions) | | |
| 2018 | $31 | $ (2 ) | $ 29 |
| 2019 | 32 | (2 ) | 30 |
| 2020 | 33 | (3 ) | 30 |
| 2021 | 34 | (3 ) | 31 |
| 2022 | 35 | (3 ) | 32 |
| 2023 to 2027 | 173 | (14 ) | 159 |

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Benefit Plan Assets

Pension plan and other postretirement benefit plan assets are managed and invested in accordance with all applicable requirements, including ERISA and the Internal Revenue Code of 1986, as amended. The Company's investment policies for both the pension plan and the other postretirement benefit plans cover a diversified mix of assets, including equity and fixed income securities, real estate, and private equity. Derivative instruments are used primarily to gain efficient exposure to the various asset classes and as hedging tools. The Company minimizes the risk of large losses primarily through diversification but also monitors and manages other aspects of risk.

The composition of the Company's pension plan and other postretirement benefit plan assets as of December 31, 2017 and 2016, along with the targeted mix of assets for each plan, is presented below:

| | Target | 2017 | 2016 |
|---|---|---|---|
| Pension plan assets: | | | |
| Domestic equity | 26 % | 31 % | 29 % |
| International equity | 25 | 25 | 22 |
| Fixed income | 23 | 24 | 29 |
| Special situations | 3 | 1 | 2 |
| Real estate investments | 14 | 13 | 13 |
| Private equity | 9 | 6 | 5 |
| Total | 100 % | 100 % | 100 % |
| Other postretirement benefit plan assets: | | | |
| Domestic equity | 42 % | 44 % | 44 % |
| International equity | 22 | 22 | 20 |
| Domestic fixed income | 28 | 28 | 29 |
| Special situations | 1 | — | 1 |
| Real estate investments | 4 | 4 | 4 |
| Private equity | 3 | 2 | 2 |
| Total | 100 % | 100 % | 100 % |

The investment strategy for plan assets related to the Company's qualified pension plan is to be broadly diversified across major asset classes. The asset allocation is established after consideration of various factors that affect the assets and liabilities of the pension plan including, but not limited to, historical and expected returns and interest rates, volatility, correlations of asset classes, the current level of assets and liabilities, and the assumed growth in assets and liabilities. Because a significant portion of the liability of the pension plan is long-term in nature, the assets are invested consistent with long-term investment expectations for return and risk. To manage the actual asset class exposures relative to the target asset allocation, the Company employs a formal rebalancing program. As additional risk management, external investment managers and service providers are subject to written guidelines to ensure appropriate and prudent investment practices. Management believes the portfolio is well-diversified with no significant concentrations of risk.

Investment Strategies

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

- Domestic equity. A mix of large and small capitalization stocks with generally an equal distribution of value and growth attributes, managed both actively and through passive index approaches.
- International equity. A mix of growth stocks and value stocks with both developed and emerging market exposure, managed both actively and through passive index approaches.
- Fixed income. A mix of domestic and international bonds.
- Trust-owned life insurance (TOLI). Investments of the Company's taxable trusts aimed at minimizing the impact of taxes on the portfolio.

- Special situations. Investments in opportunistic strategies with the objective of diversifying and enhancing returns and exploiting short-term inefficiencies as well as investments in promising new strategies of a longer-term nature.

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- Real estate investments. Investments in traditional private market, equity-oriented investments in real properties (indirectly through pooled funds or partnerships) and in publicly traded real estate securities.
- Private equity. Investments in private partnerships that invest in private or public securities typically through privately-negotiated and/or structured transactions, including leveraged buyouts, venture capital, and distressed debt.

Benefit Plan Asset Fair Values

Following are the fair value measurements for the pension plan and the other postretirement benefit plan assets as of December 31, 2017 and 2016. The fair values presented are prepared in accordance with GAAP. For purposes of determining the fair value of the pension plan and other postretirement benefit plan assets and the appropriate level designation, management relies on information provided by the plan's trustee. This information is reviewed and evaluated by management with changes made to the trustee information as appropriate.

Valuation methods of the primary fair value measurements disclosed in the following tables are as follows:

- Domestic and international equity. Investments in equity securities such as common stocks, American depositary receipts, and real estate investment trusts that trade on a public exchange are classified as Level 1 investments and are valued at the closing price in the active market. Equity investments with unpublished prices (i.e. pooled funds) are valued as Level 2, when the underlying holdings used to value the investment are comprised of Level 1 or Level 2 equity securities.
- Fixed income. Investments in fixed income securities are generally classified as Level 2 investments and are valued based on prices reported in the market place. Additionally, the value of fixed income securities takes into consideration certain items such as broker quotes, spreads, yield curves, interest rates, and discount rates that apply to the term of a specific instrument.
- TOLI. Investments in TOLI policies are classified as Level 2 investments and are valued based on the underlying investments held in the policy's separate account. The underlying assets are equity and fixed income pooled funds that are comprised of Level 1 and Level 2 securities.
- Real estate investments, private equity, and special situations investments. Investments in real estate, private equity, and special situations are generally classified as Net Asset Value as a Practical Expedient, since the underlying assets typically do not have publicly available observable inputs. The fund manager values the assets using various inputs and techniques depending on the nature of the underlying investments. Techniques may include purchase multiples for comparable transactions, comparable public company trading multiples, discounted cash flow analysis, prevailing market capitalization rates, recent sales of comparable investments, and independent third-party appraisals. The fair value of partnerships is determined by aggregating the value of the underlying assets less liabilities.

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The fair values of pension plan assets as of December 31, 2017 and 2016 are presented below. These fair value measurements exclude cash, receivables related to investment income, pending investments sales, and payables related to pending investment purchases.

| | 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(*) | $572 | $ 276 | $ — | $ — | $848 |
| International equity(*) | 370 | 333 | — | — | 703 |
| Fixed income: | | | | | |
| U.S. Treasury, government, and agency bonds | — | 200 | — | — | 200 |
| Mortgage- and asset-backed securities | — | 2 | — | — | 2 |
| Corporate bonds | — | 286 | — | — | 286 |
| Pooled funds | — | 155 | — | — | 155 |
| Cash equivalents and other | 51 | 3 | — | — | 54 |
| Real estate investments | 111 | — | — | 283 | 394 |
| Special situations | — | — | — | 43 | 43 |
| Private equity | — | — | — | 159 | 159 |
| Total | $1,104 | $ 1,255 | $ — | $ 485 | $2,844 |

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

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| | 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[*] | $477 | $ 220 | $ — | $ — | $697 |
| International equity[*] | 292 | 264 | — | — | 556 |
| Fixed income: | | | | | |
| U.S. Treasury, government, and agency bonds | — | 140 | — | — | 140 |
| Mortgage- and asset-backed securities | — | 3 | — | — | 3 |
| Corporate bonds | — | 235 | — | — | 235 |
| Pooled funds | — | 124 | — | — | 124 |
| Cash equivalents and other | 236 | 1 | — | — | 237 |
| Real estate investments | 74 | — | — | 274 | 348 |
| Special situations | — | — | — | 43 | 43 |
| Private equity | — | — | — | 130 | 130 |
| Total | $1,079 | $ 987 | $ — | $ 447 | $2,513 |

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

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The fair values of 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 investments sales, and payables related to pending investment purchases.

| | 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(*) | $52 | $ 12 | $ — | $ — | $64 |
| International equity(*) | 16 | 14 | — | — | 30 |
| Fixed income: | | | | | |
| U.S. Treasury, government, and agency bonds | — | 11 | — | — | 11 |
| Corporate bonds | — | 12 | — | — | 12 |
| Pooled funds | — | 7 | — | — | 7 |
| Cash equivalents and other | 2 | — | — | — | 2 |
| Trust-owned life insurance | — | 253 | — | — | 253 |
| Real estate investments | 5 | — | — | 12 | 17 |
| Special situations | — | — | — | 2 | 2 |
| Private equity | — | — | — | 7 | 7 |
| Total | $75 | $ 309 | $ — | $ 21 | $405 |

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

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| | Fair Value Measurements Using | | | | |
|---|---|---|---|---|---|
| | Quoted Prices in Active Markets for Identical Assets | Significant Other Observable Inputs | Significant Unobservable Inputs | Net Asset Value as a Practical Expedient | |
| As of December 31, 2016: | (Level 1) | (Level 2) | (Level 3) | (NAV) | Total |
| | (in millions) | | | | |
| Assets: | | | | | |
| Domestic equity(*) | $51 | $ 10 | $ — | $ — | $61 |
| International equity(*) | 13 | 12 | — | — | 25 |
| Fixed income: | | | | | |
| U.S. Treasury, government, and agency bonds | — | 7 | — | — | 7 |
| Corporate bonds | — | 10 | — | — | 10 |
| Pooled funds | — | 5 | — | — | 5 |
| Cash equivalents and other | 14 | — | — | — | 14 |
| Trust-owned life insurance | — | 220 | — | — | 220 |
| Real estate investments | 4 | — | — | 12 | 16 |
| Special situations | — | — | — | 2 | 2 |
| Private equity | — | — | — | 6 | 6 |
| Total | $82 | $ 264 | $ — | $ 20 | $366 |

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

Employee Savings Plan

The Company also sponsors a 401(k) defined contribution plan covering substantially all employees. The Company matches a portion of the first 6% of employee base salary contributions. The maximum Company match is 5.1% of an employee's base salary. Total matching contributions made to the plan for 2017, 2016, and 2015 were $23 million, $23 million, and $22 million, respectively.

3. CONTINGENCIES AND REGULATORY MATTERS

General Litigation Matters

The Company is subject to certain claims and legal actions arising in the ordinary course of business. In addition, the Company's business activities are subject to extensive governmental regulation related to public health and the environment, such as regulation of air emissions and water discharges. Litigation over environmental issues and claims of various types, including property damage, personal injury, common law nuisance, and citizen enforcement of environmental requirements such as 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 the Company cannot be predicted at this time; however, for current proceedings not specifically reported herein, management does not anticipate that the ultimate liabilities, if any, arising from such current proceedings would have a material effect on the Company's financial statements.

Environmental Matters

Environmental Remediation

The Company must comply with environmental laws and regulations that cover the handling and disposal of waste and releases of hazardous substances. Under these various laws and regulations, the Company could incur substantial costs to clean up affected sites. The Company conducts studies to determine the extent of any required cleanup and has recognized in its financial statements the estimated costs to clean up known sites. Amounts for cleanup and ongoing monitoring costs were not material for any year presented. The Company may be liable for some or all required cleanup costs for additional sites that may require

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environmental remediation. The Company recognizes a liability for environmental remediation costs only when it determines a loss is probable and reasonably estimable.

Nuclear Fuel Disposal Costs

Acting through the DOE and pursuant to the Nuclear Waste Policy Act of 1982, the U.S. government entered into a contract with the Company that requires the DOE to dispose of spent nuclear fuel and high level radioactive waste generated at Plant Farley beginning no later than January 31, 1998. The DOE has yet to commence the performance of its contractual and statutory obligation to dispose of spent nuclear fuel. Consequently, the Company has pursued and continues to pursue legal remedies against the U.S. government for its partial breach of contract.

In 2014, the Court of Federal Claims entered a judgment in favor of the Company in its spent nuclear fuel lawsuit seeking damages for the period from January 1, 2005 through December 31, 2010. In 2015, the Company recovered approximately $26 million, which was applied to reduce the cost of service for the benefit of customers.

In 2014, the Company filed a lawsuit against the U.S. government for the costs of continuing to store spent nuclear fuel at Plant Farley for the period from January 1, 2011 through December 31, 2013. The damage period was subsequently extended to December 31, 2014. On October 10, 2017, the Company filed an additional lawsuit against the U.S. government in the Court of Federal Claims for the costs of continuing to store spent nuclear fuel at Plant Farley 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, the Company expects to credit any recovery back for the benefit of customers in accordance with direction from the Alabama PSC and, therefore, no material impact on the Company's net income is expected.

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

FERC Matters

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

In December 2016, the traditional electric operating companies (including the Company) and Southern Power filed an amendment to their market-based rate tariff that proposed certain changes to the energy auction, as well as several non-tariff changes. On February 2, 2017, the FERC issued an order accepting all such changes subject to an additional condition of cost-based price caps for certain sales outside of the energy auction, finding that all of these changes would provide adequate alternative mitigation for the traditional electric operating companies' (including the Company's) and Southern Power's potential to exert market power in certain areas served by the traditional electric operating companies (including the Company) and in some adjacent areas. On May 17, 2017, the FERC accepted the traditional electric operating companies' (including the Company's) 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.

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On October 25, 2017, the FERC issued an order in response to the traditional electric operating companies' (including the Company's) and Southern Power's June 29, 2017 triennial updated market power analysis. The FERC directed the traditional electric operating companies (including the Company) 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 (including the Company) 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.
Retail Regulatory Matters
Rate RSE
The Alabama PSC has adopted Rate RSE that provides for periodic annual adjustments based upon the Company's projected weighted cost of equity (WCE) compared to an allowable range. Rate RSE adjustments are based on forward-looking information for the applicable upcoming calendar year. Retail rates remain unchanged when the WCE ranges between 5.75% and 6.21% with an adjusting point of 5.98% and eligibility for a performance-based adder of seven basis points, or 0.07%, to the WCE adjusting point if the Company (i) has an "A" credit rating equivalent with at least one of the recognized rating agencies or (ii) is in the top one-third of a designated customer value benchmark survey. Rate RSE adjustments for any two-year period, when averaged together, cannot exceed 4.0% and any annual adjustment is limited to 5.0%. If the Company's actual retail return is above the allowed WCE range, the excess will be refunded to customers unless otherwise directed by the Alabama PSC; however, there is no provision for additional customer billings should the actual retail return fall below the WCE range.
At December 31, 2016, the Company's retail return exceeded the allowed WCE range which resulted in the Company establishing a $73 million Rate RSE refund liability. In accordance with an Alabama PSC order issued on February 14, 2017, the Company 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, the Company's actual retail return was within the allowed WCE range. On December 1, 2017, the Company 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, the Company 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
The Company'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. The Company 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 the Company 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, the Company 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, the Company eliminated the under recovered balance in Rate CNP PPA at December 31, 2016, which totaled approximately $142 million. As discussed herein under "Rate RSE," the Company 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 the Company's next depreciation study, which is expected to occur within the next two to four years. The Company's current depreciation study became effective January 1, 2017.

Rate CNP Compliance

Rate CNP Compliance allows for the recovery of the Company's retail costs associated with laws, regulations, and other such mandates directed at the utility industry involving the environment, security, reliability, safety, sustainability, or similar considerations impacting the Company's facilities or operations. Rate CNP Compliance is based on forward-looking information and provides for the recovery of these costs pursuant to a factor that is calculated annually. Compliance costs to be recovered include operations and maintenance expenses, depreciation, and a return on certain invested capital. Revenues for Rate CNP Compliance, as recorded on the financial statements, are adjusted for differences in actual recoverable costs and amounts billed in current regulated rates. Accordingly, changes in the billing factor will have no significant effect on the Company's revenues or net income, but will affect annual cash flow. Changes in 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, the Company 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 the Company's next depreciation study, which is expected to occur within the next two to four years. The Company's current depreciation study became effective January 1, 2017.

On December 5, 2017, the Alabama PSC issued a consent order that the Company leave in effect for 2018 the factors associated with the Company'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, the Company had a deferred under recovered regulatory clause revenues balance of $17 million and $9 million, respectively.

Rate ECR

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

In accordance with an accounting order issued on February 17, 2017 by the Alabama PSC, the Company 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 the Company's next depreciation study, which is expected to occur within the next two to four years. The Company's current depreciation study became effective January 1, 2017.

On December 5, 2017, the Alabama PSC issued a consent order that the Company 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, the Company's under recovered fuel costs totaled $25 million, which is included in deferred under recovered regulatory clause revenues. At December 31, 2016, the Company 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, the Company maintains a reserve for operations and maintenance expenses to cover the cost of damages from major storms to its transmission and distribution facilities. The order approves a separate monthly Rate NDR charge to customers consisting of two components. The first component is intended to establish and maintain a reserve balance for future storms and is an on-going part of customer billing. 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 the Company authority to record a deficit balance in the NDR when costs of storm damage exceed any established reserve balance. Absent further Alabama PSC approval, the maximum total Rate NDR charge consisting of both components is $10 per month per non-residential customer account and $5 per month per residential customer account. The Company has the authority, based on an order from the Alabama PSC, to accrue certain additional amounts as circumstances warrant. The order allows for reliability-related expenditures to be charged against the additional accruals when the NDR balance exceeds $75 million. The Company may designate a portion of the NDR to reliability-related expenditures as a part of an annual budget process for the following year or during the current year for identified unbudgeted reliability-related expenditures that are

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incurred. Accruals that have not been designated can be used to offset storm charges. Additional accruals to the NDR will enhance the Company's ability to deal with the financial effects of future natural disasters, promote system reliability, and offset costs retail customers would otherwise bear. No such accruals were recorded or designated in any period presented.

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. The Company 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, the Company is allowed to establish a regulatory asset to record the unrecovered investment costs, including the unrecovered plant asset balance and the unrecovered costs associated with site removal and closure associated with future unit retirements caused by environmental regulations. 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.

The Company retired Plant Gorgas Units 6 and 7 (200 MWs) and Plant Barry Unit 3 (225 MWs) in 2015. Additionally, the Company 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, the Company also ceased using coal at Plant Greene County Units 1 and 2 (300 MWs representing the Company's ownership interest) and began operating Units 1 and 2 solely on natural gas in June 2016 and July 2016, respectively.

In accordance with this accounting order from the Alabama PSC, the Company transferred the unrecovered plant asset balances to 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 the Company's financial statements.

4. JOINT OWNERSHIP AGREEMENTS

The Company and Georgia Power own equally all of the outstanding capital stock of SEGCO, which owns electric generating units with a total rated capacity of 1,020 MWs, as well as associated transmission facilities. SEGCO uses natural gas as the primary fuel source for 1,000 MWs of its generating capacity. The capacity of these units is sold equally to the Company and Georgia Power under a power contract. The Company and Georgia Power make payments sufficient to provide for the operating expenses, taxes, interest expense, and ROE. The Company's share of purchased power totaled $76 million in 2017, $55 million in 2016, and $76 million in 2015 and is included in "Purchased power from affiliates" in the statements of income. The Company accounts for SEGCO using the equity method.

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

At December 31, 2017, the capitalization of SEGCO consisted of $95 million of equity and $125 million of long-term debt on which the annual interest requirement is $4 million. In addition, SEGCO had short-term debt outstanding of $14 million. SEGCO paid $24 million of dividends in 2017 and 2016 compared to an immaterial amount in 2015, of which one-half of each was paid to the Company. In addition, the Company recognizes 50% of SEGCO's net income.

The Company, which owns and operates a generating unit adjacent to the SEGCO generating units, has a joint ownership agreement with SEGCO for the ownership of an associated gas pipeline. The Company owns 14% of the pipeline with the remaining 86% owned by SEGCO.

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In addition to the Company's ownership of SEGCO and joint ownership of an associated gas pipeline, the Company's percentage ownership and investment in jointly-owned generating plants at December 31, 2017 were as follows:

| Facility | Total MW Capacity | Company Ownership | Plant in Service | Accumulated Depreciation | Construction Work in Progress |
|---|---|---|---|---|---|
| | | | (in millions) | | |
| Greene County | 500 | 60.00 % [(1)] | $172 | $ 65 | $ 2 |
| Plant Miller Units 1 and 2 | 1,320 | 91.84 % [(2)] | 1,717 | 619 | 54 |

(1) Jointly owned with an affiliate, Mississippi Power.
(2) Jointly owned with PowerSouth Energy Cooperative, Inc.

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

## 5. INCOME TAXES

On behalf of the Company, Southern Company files a consolidated federal income tax return and various combined and separate state income tax returns. Under a joint consolidated income tax allocation agreement, each Southern Company subsidiary's current and deferred tax expense is computed on a stand-alone basis and no subsidiary is allocated more current expense than would be paid if it filed a separate income tax return. In accordance with IRS regulations, each company is jointly and severally liable for the federal tax liability.

### Federal Tax Reform Legislation

Following the enactment of 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, the Company considers all amounts recorded in the financial statements as a result of Tax Reform Legislation to be "provisional" as discussed in SAB 118 and subject to revision. The Company is awaiting additional guidance from industry and income tax authorities in order to finalize its accounting. The ultimate impact of 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 "Retail Regulatory Matters – Rate RSE" for additional information.

### Current and Deferred Income Taxes

Details of income tax provisions are as follows:

| | 2017 | 2016 | 2015 |
|---|---|---|---|
| | (in millions) | | |
| Federal — | | | |
| Current | $136 | $103 | $110 |
| Deferred | 336 | 339 | 320 |
| | 472 | 442 | 430 |
| State — | | | |
| Current | 23 | 20 | 8 |
| Deferred | 73 | 69 | 68 |
| | 96 | 89 | 76 |
| Total | $568 | $531 | $506 |

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The tax effects of temporary differences between the carrying amounts of assets and liabilities in the financial statements and their respective tax bases, which give rise to deferred tax assets and liabilities, are as follows:

| | 2017 | 2016 |
|---|---|---|
| | (in millions) | |
| Deferred tax liabilities — | | |
| Accelerated depreciation | $2,336 | $4,307 |
| Property basis differences | 398 | 456 |
| Premium on reacquired debt | 16 | 26 |
| Employee benefit obligations | 162 | 201 |
| Regulatory assets associated with employee benefit obligations | 260 | 393 |
| Asset retirement obligations | 220 | 289 |
| Regulatory assets associated with asset retirement obligations | 249 | 347 |
| Other | 147 | 179 |
| Total | 3,788 | 6,198 |
| Deferred tax assets — | | |
| Federal effect of state deferred taxes | 143 | 266 |
| Unbilled fuel revenue | 22 | 36 |
| Storm reserve | 5 | 21 |
| Employee benefit obligations | 286 | 427 |
| Other comprehensive losses | 10 | 19 |
| Asset retirement obligations | 469 | 636 |
| Other | 93 | 139 |
| Total | 1,028 | 1,544 |
| Accumulated deferred income taxes, net | $2,760 | $4,654 |

The implementation of Tax Reform Legislation significantly reduced accumulated deferred income taxes, partially offset by bonus depreciation provisions in the 2015 Protecting Americans from Tax Hikes Act. 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 $240 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 $2.1 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 are amortized over the average life of the related property with such amortization normally applied as a credit to reduce depreciation in the statements of income. Credits amortized in this manner amounted to $7 million in 2017 and $8 million annually in 2016 and 2015. At December 31, 2017, the Company had federal ITC carryforwards which are expected to result in $9 million of federal income tax benefits. The federal ITC carryforwards begin expiring in 2038 but are expected to be fully utilized by 2027. The ultimate outcome of these matters cannot be determined at this time.

Tax Credit Carryforwards

The Company had state credit carryforwards for the state of Alabama of approximately $4 million, which begin expiring in 2023 but are expected to be fully utilized.

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Effective Tax Rate

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

| | 2017 | 2016 | 2015 |
|---|---|---|---|
| Federal statutory rate | 35.0% | 35.0% | 35.0% |
| State income tax, net of federal deduction | 4.4 | 4.2 | 3.8 |
| Non-deductible book depreciation | 0.9 | 1.0 | 1.2 |
| AFUDC equity | (1.0) | (0.7) | (1.6) |
| Tax Reform Legislation | 0.3 | — | — |
| Other | — | (0.7) | — |
| Effective income tax rate | 39.6% | 38.8% | 38.4% |

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 the Company's overall effective tax rate. See Note 1 under "Recently Issued Accounting Standards" for additional information.

Unrecognized Tax Benefits

The Company has no material unrecognized tax benefits for the periods presented. The Company classifies interest on tax uncertainties as interest expense. Accrued interest for unrecognized tax benefits was immaterial and the Company did not accrue any penalties on uncertain tax positions.

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

The IRS has finalized its audits of Southern Company's consolidated federal income tax returns through 2016. Southern Company is a participant in the Compliance Assurance Process of the IRS. The audits for the Company's state income tax returns have either been concluded, or the statute of limitations has expired, for years prior to 2011.

6. FINANCING

Long-Term Debt Payable to an Affiliated Trust

The Company has formed a wholly-owned trust subsidiary for the purpose of issuing preferred securities. The proceeds of the related equity investments and preferred security sales were loaned back to the Company through the issuance of junior subordinated notes totaling $206 million 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. The Company considers that the mechanisms and obligations relating to the preferred securities issued for its benefit, taken together, constitute a full and unconditional guarantee by it of the trust's payment obligations with respect to these securities. At December 31, 2017 and 2016, trust preferred securities of $200 million were outstanding. See Note 1 under "Variable Interest Entities" for additional information on the accounting treatment for this trust and the related securities.

Securities Due Within One Year

At December 31, 2017, the Company had no securities due within one year. At December 31, 2016, the Company had $561 million of senior notes and pollution control revenue bonds due within one year.

Maturities through 2022 applicable to total long-term debt are as follows: $200 million in 2019; $250 million in 2020; $310 million in 2021; and $750 million in 2022. There are no scheduled maturities in 2018.

Bank Term Loans

At both December 31, 2017 and 2016, the Company had $45 million of outstanding bank term loan agreements, which are reflected in the statements of capitalization as long-term debt.

These bank loans have covenants that limit debt levels to 65% of total capitalization, as defined in the agreements. For purposes of calculating these covenants, any long-term notes payable to affiliated trusts are excluded from debt but included in capitalization. At December 31, 2017, the Company was in compliance with its debt limits.

Pollution Control Revenue Bonds

Pollution control revenue bond obligations represent loans to the Company from public authorities of funds or installment purchases of pollution control and solid waste disposal facilities financed by funds derived from sales by public authorities of revenue bonds. The Company is required to make payments sufficient for the authorities to meet principal and interest requirements of such bonds. The Company incurred no obligations related to the issuance of pollution control revenue bonds in 2017.

In August 2017, the Company repaid at maturity $36.1 million aggregate principal amount of Series 1993-A, 1993-B, and 1993-C Industrial Development Board of the City of Mobile, Alabama Pollution Control Revenue Refunding Bonds (Alabama Power Company Project).

The Company had $1.06 billion and $1.10 billion of tax-exempt pollution control revenue bond obligations outstanding at December 31, 2017 and 2016, respectively, including pollution control revenue bonds classified as due within one year.

Senior Notes

In March 2017, the Company issued $550 million aggregate principal amount of Series 2017A 2.45% Senior Notes due March 30, 2022. The proceeds were used to repay the Company's short-term indebtedness and for general corporate purposes, including the Company's continuous construction program.

In November 2017, the Company issued $550 million aggregate principal amount of Series 2017B 3.70% Senior Notes due December 1, 2047. The proceeds were used for general corporate purposes, including the Company's continuous construction program.

At December 31, 2017 and 2016, the Company had $6.4 billion and $5.8 billion of senior notes outstanding, respectively, including senior notes classified as due within one year. At December 31, 2017 and 2016, the Company did not have any outstanding secured debt.

Redeemable Preferred and Preference Stock

The Company currently has preferred stock, Class A preferred stock, and common stock outstanding. The Company also has authorized preference stock, none of which is outstanding. The Company's preferred stock and Class A preferred stock, without preference between classes, rank senior to the Company's common stock with respect to payment of dividends and voluntary and involuntary dissolution. The preferred stock and Class A preferred stock of the Company contain a feature that allows the holders to elect a majority of the Company's board of directors if preferred dividends are not paid for four consecutive quarters. Because such a potential redemption-triggering event is not solely within the control of the Company, the preferred stock and Class A preferred stock is presented as "Redeemable Preferred Stock" in a manner consistent with temporary equity under applicable accounting standards.

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The Company's preferred stock is subject to redemption at a price equal to the par value plus a premium. The Company's Class A preferred stock is subject to redemption at a price equal to the stated capital. All series of the Company's preferred stock currently are subject to redemption at the option of the Company. The Class A preferred stock is subject to redemption on or after October 1, 2022, or following the occurrence of a rating agency event. Information for each outstanding series is in the table below:

| Preferred/Preference Stock | Par Value/Stated Capital Per Share | Shares Outstanding | Redemption Price Per Share |
|---|---|---|---|
| 4.92% Preferred Stock | $100 | 80,000 | $103.23 |
| 4.72% Preferred Stock | $100 | 50,000 | $102.18 |
| 4.64% Preferred Stock | $100 | 60,000 | $103.14 |
| 4.60% Preferred Stock | $100 | 100,000 | $104.20 |
| 4.52% Preferred Stock | $100 | 50,000 | $102.93 |
| 4.20% Preferred Stock | $100 | 135,115 | $105.00 |
| 5.00% Class A Preferred Stock | $25 | 10,000,000 | Stated Capital(*) |

(*) Prior to October 1, 2022: $25.50; on or after October 1, 2022: Stated Capital

In September 2017, the Company 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 proceeds were used in October 2017 to redeem all 2 million shares ($50 million aggregate stated capital) of 6.50% Series Preference Stock, 6 million shares ($150 million aggregate stated capital) of 6.45% Series Preference Stock, and 1.52 million shares ($38 million aggregate stated capital) of 5.83% Class A Preferred Stock and for other general corporate purposes, including the Company's continuous construction program.

There were no changes for the year ended December 31, 2016 in redeemable preferred stock or preference stock of the Company.

Dividend Restrictions

The Company can only pay dividends to Southern Company out of retained earnings or paid-in-capital.

Bank Credit Arrangements

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

| Expires | | | | | Expires Within One Year | |
|---|---|---|---|---|---|---|
| 2018 | 2020 | 2022 | Total | Unused | Term Out | No Term Out |
| (in millions) | | | (in millions) | | (in millions) | |
| $35 | $500 | $800 | $1,335 | $1,335 | $ — | $ 35 |

Most of the bank credit arrangements require payment of a commitment fee based on the unused portion of the commitments or the maintenance of compensating balances with the banks. Commitment fees average less than 1/4 of 1% for the Company. Compensating balances are not legally restricted from withdrawal.

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

Most of the Company's bank credit arrangements contain covenants that limit the Company's debt level to 65% of total capitalization, as defined in the arrangements. For purposes of calculating these covenants, any long-term notes payable to affiliated trusts are excluded from debt but included in capitalization. At December 31, 2017, the Company was in compliance with the debt limit covenants.

A portion of the unused credit with banks is allocated to provide liquidity support to the Company's pollution control revenue bonds and commercial paper programs. The amount of variable rate pollution control revenue bonds outstanding requiring liquidity support was $854 million as of December 31, 2017. In addition, at December 31, 2017, the Company had $120 million of fixed rate pollution control revenue bonds outstanding that were required to be remarketed within the next 12 months.

The Company borrows through commercial paper programs that have the liquidity support of the committed bank credit arrangements described above. The Company may also make short-term borrowings through various other arrangements with

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banks. At December 31, 2017, the Company had $3 million in short-term debt outstanding and none at December 31, 2016. At December 31, 2017, the Company had regulatory approval to have outstanding up to $2.0 billion of short-term borrowings.

7. COMMITMENTS

Fuel and Purchased Power Agreements

To supply a portion of the fuel requirements of its generating plants, the Company has entered into various long-term commitments for the procurement and delivery of fossil and nuclear fuel which are not recognized on the balance sheets. In 2017, 2016, and 2015, the Company incurred fuel expense of $1.2 billion, $1.3 billion, and $1.3 billion, respectively, the majority of which was purchased under long-term commitments. The Company expects that a substantial amount of its future fuel needs will continue to be purchased under long-term commitments.

In addition, the Company has entered into various long-term commitments for the purchase of capacity and electricity, some of which are accounted for as operating leases. Total capacity expense under PPAs accounted for as operating leases was $41 million, $42 million, and $38 million for 2017, 2016, and 2015, respectively. Total estimated minimum long-term obligations at December 31, 2017 were as follows:

| | Operating Lease PPAs |
|---|---|
| | (in millions) |
| 2018 | $ 41 |
| 2019 | 43 |
| 2020 | 44 |
| 2021 | 46 |
| 2022 | 47 |
| 2023 and thereafter | — |
| Total commitments | $ 221 |

SCS may enter into various types of wholesale energy and natural gas contracts acting as an agent for the Company and all of the other traditional electric operating companies and Southern Power. Under these agreements, each of the traditional electric operating companies and Southern Power may be jointly and severally liable. Accordingly, Southern Company has entered into keep-well agreements with the Company and each of the other traditional electric operating companies to ensure the Company will not subsidize or be responsible for any costs, losses, liabilities, or damages resulting from the inclusion of Southern Power as a contracting party under these agreements.

Operating Leases

The Company has entered into operating leases with Southern Linc and third parties for the use of cellular tower space. Substantially all of these agreements have initial terms ranging from five to 10 years and renewal options of up to 20 years. The Company has entered into rental agreements for towers, coal railcars, vehicles, and other equipment with various terms and expiration dates. Total rent expense under these agreements was $25 million in 2017, $18 million in 2016, and $19 million in 2015. Of these amounts, $11 million, $14 million, and $13 million for 2017, 2016, and 2015, respectively, relate to the railcar leases and was recovered through the Company's Rate ECR. The Company includes any step rents, fixed escalations, and lease concessions in its computation of minimum lease payments.

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

| | Minimum Lease Payments[a] | | | |
|---|---|---|---|---|
| | Affiliate Operating Leases[b] | Railcars | Vehicles & Other | Total |
| | | (in millions) | | |
| 2018 | $ 8 | $ 7 | $ 6 | $ 21 |
| 2019 | 10 | 7 | 5 | 22 |
| 2020 | 8 | 7 | 3 | 18 |
| 2021 | 7 | 6 | 1 | 14 |
| 2022 | 5 | 5 | — | 10 |
| 2023 and thereafter | 16 | 4 | — | 20 |
| Total | $ 54 | $ 36 | $ 15 | $ 105 |

(a) Minimum lease payments have not been reduced by minimum sublease rentals of $3 million in the future.
(b) Includes operating leases for cellular tower space.

In addition to the above rental commitments payments, the Company has potential obligations upon expiration of certain railcar leases with respect to the residual value of the leased property. These leases have terms expiring through 2023 with maximum obligations under these leases of $12 million in 2023. There are no obligations under these leases through 2022. At the termination of the leases, the lessee may either exercise its purchase option, or the property can be sold to a third party. The Company expects that the fair market value of the leased property would substantially reduce or eliminate the Company's payments under the residual value obligations.

Guarantees

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

8. STOCK COMPENSATION

Stock-Based Compensation

Stock-based compensation primarily in the form of Southern Company performance share units and restricted stock units may be granted through the Omnibus Incentive Compensation Plan to a large segment of the Company's employees ranging from line management to executives. 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 793 current and former employees participating in the stock option, performance share unit, and restricted stock unit programs.

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.

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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. The 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.

For the years ended December 31, 2017, 2016, and 2015, employees of the Company were granted performance share units of 135,502, 249,065, and 214,709, respectively. The weighted average grant-date fair value of TSR-based performance share units granted during 2017, 2016, and 2015, determined using a Monte Carlo simulation model to estimate the TSR of Southern Company's stock among the industry peers over the performance period, was $49.07, $45.15, and $46.42, respectively. 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, $48.86, and $47.78, respectively.

For the years ended December 31, 2017, 2016, and 2015, total compensation cost for performance share units recognized in income was $9 million, $15 million, and $13 million, respectively, with the related tax benefit also recognized in income of $4 million, $6 million, and $5 million, respectively. The compensation cost related to the grant of Southern Company performance share units to the Company's employees is recognized in the Company's financial statements with a corresponding credit to equity, representing a capital contribution from Southern Company. As of December 31, 2017, $2 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.

For the year ended December 31, 2017, employees of the Company were granted 58,001 restricted stock units. The weighted average grant-date fair value of restricted stock units granted during 2017 was $49.21.
For the year ended December 31, 2017, total compensation cost for restricted stock units recognized in income was $3 million with the related tax benefit also recognized in income of $1 million. As of December 31, 2017, total unrecognized compensation cost related to restricted stock units was immaterial.

Stock Options

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

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The compensation cost related to the grant of Southern Company stock options to the Company's employees is recognized in the Company's financial statements with a corresponding credit to equity, representing a capital contribution from Southern Company. Compensation cost and related tax benefits recognized in the Company's financial statements were not material for any year presented. As of December 31, 2017, all compensation cost related to stock option awards has been recognized.
The total intrinsic value of options exercised during the years ended December 31, 2017, 2016, and 2015 was $12 million, $21 million, and $8 million, respectively. No cash proceeds are received by the Company upon the exercise of stock options. The actual tax benefit realized by the Company for the tax deductions from stock option exercises totaled $5 million, $8 million, and $3 million for the years ended December 31, 2017, 2016, and 2015, respectively. Prior to the adoption of ASU 2016-09 in 2016, the excess tax benefits related to the exercise of stock options were recognized in the Company's financial statements with a credit to equity. Upon the adoption of ASU 2016-09, beginning in 2016, all tax benefits related to the exercise of stock options are recognized in income. As of December 31, 2017, the aggregate intrinsic value for the options outstanding and exercisable was $17 million.
9. NUCLEAR INSURANCE
Under the Price-Anderson Amendments Act (Act), the Company maintains agreements of indemnity with the NRC that, together with private insurance, cover third-party liability arising from any nuclear incident occurring at Plant Farley. The Act provides funds up to $13.4 billion for public liability claims that could arise from a single nuclear incident. Plant Farley is insured against this liability to a maximum of $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. The Company could be assessed up to $127 million per incident for each licensed reactor it operates but not more than an aggregate of $19 million per incident to be paid in a calendar year for each reactor. Such maximum assessment, excluding any applicable state premium taxes, for the Company is $255 million per incident but not more than an aggregate of $38 million to be paid for each incident in any one year. Both the maximum assessment per reactor and the maximum yearly assessment are adjusted for inflation at least every five years. The next scheduled adjustment is due no later than September 10, 2018.
The Company is a member of Nuclear Electric Insurance Limited (NEIL), a mutual insurer established to provide property damage insurance in an amount up to $1.5 billion for members' operating nuclear generating facilities. Additionally, the Company has NEIL policies that currently provide decontamination, excess property insurance, and premature decommissioning coverage up to $1.25 billion for nuclear losses 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. The Company purchases limits based on the projected full cost of replacement power and has elected a 12-week deductible waiting period.
Under each of the NEIL policies, members are subject to assessments each year if losses exceed the accumulated funds available to the insurer. The maximum annual assessments for the Company as of December 31, 2017 under the NEIL policies would be $55 million.
Claims resulting from terrorist acts are covered under both the ANI and NEIL policies (subject to normal policy limits). The aggregate, however, that NEIL will pay for all claims resulting from terrorist acts in any 12-month period is $3.2 billion plus such additional amounts NEIL can recover through reinsurance, indemnity, or other sources.
For all on-site property damage insurance policies for commercial nuclear power plants, the NRC requires that the proceeds of such policies shall be dedicated first for the sole purpose of placing the reactor in a safe and stable condition after an accident. Any remaining proceeds are to be applied next toward the costs of decontamination and debris removal operations ordered by the NRC, and any further remaining proceeds are to be paid either to the

Company or to its debt trustees as may be appropriate under the policies and applicable trust indentures. In the event of a loss, the amount of insurance available might not be adequate to cover property damage and other expenses incurred. Uninsured losses and other expenses, to the extent not recovered from customers, would be borne by the Company and could have a material effect on the Company's financial condition and results of operations.
All retrospective assessments, whether generated for liability, property, or replacement power, may be subject to applicable state premium taxes.

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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 | | | | |
|---|---|---|---|---|---|
| | Quoted Prices in Active Markets for Identical Assets | Significant Other Observable Inputs | Significant Unobservable Inputs | Net Asset Value as a Practical Expedient | |
| As of December 31, 2017: | (Level 1) | (Level 2) | (Level 3) | (NAV) | Total |
| | (in millions) | | | | |
| Assets: | | | | | |
| Energy-related derivatives | $— | $ 4 | $ — | $ — | $4 |
| Nuclear decommissioning trusts:(*) | | | | | |
| Domestic equity | 442 | 81 | — | — | 523 |
| Foreign equity | 62 | 59 | — | — | 121 |
| U.S. Treasury and government agency securities | — | 24 | — | — | 24 |
| Corporate bonds | 21 | 160 | — | — | 181 |
| Mortgage and asset backed securities | — | 18 | — | — | 18 |
| Private equity | — | — | — | 29 | 29 |
| Other | 6 | — | — | — | 6 |
| Cash equivalents | 349 | — | — | — | 349 |
| Total | $880 | $ 346 | $ — | $ 29 | $1,255 |
| Liabilities: | | | | | |
| Energy-related derivatives | $— | $ 10 | $ — | $ — | $10 |

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

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As of December 31, 2016, assets and liabilities measured at fair value on a recurring basis during the period, together with their associated level of the fair value hierarchy, were as follows:

| | Fair Value Measurements Using | | | | |
|---|---|---|---|---|---|
| | Quoted Prices in Active Markets for Identical Assets | Significant Other Observable Inputs | Significant Unobservable Inputs | Net Asset Value as a Practical Expedient | |
| As of December 31, 2016: | (Level 1) | (Level 2) | (Level 3) | (NAV) | Total |
| | (in millions) | | | | |
| Assets: | | | | | |
| Energy-related derivatives | $— | $ 20 | $ — | $ — | $ 20 |
| Nuclear decommissioning trusts:(*) | | | | | |
| Domestic equity | 385 | 72 | — | — | 457 |
| Foreign equity | 48 | 47 | — | — | 95 |
| U.S. Treasury and government agency securities | — | 21 | — | — | 21 |
| Corporate bonds | 22 | 146 | — | — | 168 |
| Mortgage and asset backed securities | — | 19 | — | — | 19 |
| Private equity | — | — | — | 20 | 20 |
| Other | — | 10 | — | — | 10 |
| Cash equivalents | 262 | — | — | — | 262 |
| Total | $ 717 | $ 335 | $ — | $ 20 | $ 1,072 |
| Liabilities: | | | | | |
| Energy-related derivatives | $— | $ 9 | $ — | $ — | $ 9 |

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

Valuation Methodologies

The energy-related derivatives primarily consist of over-the-counter financial products for natural gas and physical power products, including, from time to time, basis swaps. These are standard products used within the energy industry and are valued using the market approach. The inputs used are mainly from observable market sources, such as forward natural gas prices, power prices, implied volatility, and overnight index swap interest rates. Interest rate derivatives are also standard over-the-counter products that are valued using observable market data and assumptions commonly used by market participants. The fair value of interest rate derivatives reflects the net present value of expected payments and receipts under the swap agreement based on the market's expectation of future interest rates. Additional inputs to the net present value calculation may include the contract terms, counterparty credit risk, and occasionally, implied volatility of interest rate options. The interest rate derivatives are categorized as Level 2 under Fair Value Measurements as these inputs are based on observable data and valuations of similar instruments. See Note 11 for additional information on how these derivatives are used.

The NRC requires licensees of commissioned nuclear power reactors to establish a plan for providing reasonable assurance of funds for future decommissioning. For fair value measurements of the investments within the nuclear decommissioning trusts, external pricing vendors are designated for each asset class with each security specifically assigned a primary pricing source. For investments held within commingled funds, fair value is determined at the end of each business day through the net asset value, which is established by obtaining the underlying securities' individual prices from the primary pricing source. See Note 1 under "Nuclear Decommissioning" for additional information. A market price secured from the primary source vendor is then evaluated by management in its valuation of the assets within the trusts. As a general approach, fixed income market pricing vendors gather market data (including indices and market research reports) and integrate relative credit information, observed market movements, and sector news into proprietary pricing models, pricing systems, and mathematical tools. Dealer quotes and other market information, including live trading levels and pricing analysts' judgments, are also obtained when available.

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As of December 31, 2017 and 2016, the fair value measurements of private equity investments held in the nuclear decommissioning trusts that are calculated at net asset value per share (or its equivalent) as a practical expedient, as well as the nature and risks of those investments, were as follows:

| | Fair Value | Unfunded Commitments | Redemption Frequency | Redemption Notice Period |
|---|---|---|---|---|
| | (in millions) | | | |
| As of December 31, 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 of these investments 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:

| | Carrying Amount | Fair Value |
|---|---|---|
| | (in millions) | |
| Long-term debt, including securities due within one year: | | |
| 2017 | $7,625 | $8,305 |
| 2016 | $7,092 | $7,544 |

The fair values are determined using Level 2 measurements and are based on quoted market prices for the same or similar issues or on the current rates available to the Company.

11. DERIVATIVES

The Company is exposed to market risks, including commodity price risk and interest rate risk. To manage the volatility attributable to these exposures, the Company nets its exposures, where possible, to take advantage of natural offsets and enters into various derivative transactions for the remaining exposures pursuant to the Company's policies in areas such as counterparty exposure and risk management practices. The Company's policy is that derivatives are to be used primarily for hedging purposes and mandates strict adherence to all applicable risk management policies. Derivative positions are monitored using techniques including, but not limited to, market valuation, value at risk, stress testing, and sensitivity analysis. Derivative instruments are recognized at fair value in the balance sheets as either assets or liabilities and are presented on a net basis. See Note 10 for additional information. In the statements of cash flows, the cash impacts of settled energy-related and interest rate derivatives are recorded as operating activities.

Energy-Related Derivatives

The Company enters into energy-related derivatives to hedge exposures to electricity, gas, and other fuel price changes. However, due to cost-based rate regulations and other various cost recovery mechanisms, the Company has limited exposure to market volatility in energy-related commodity prices. The Company manages fuel-hedging programs, implemented per the guidelines of the Alabama PSC, through the use of financial derivative contracts, which is expected to continue to mitigate price volatility.

Energy-related derivative contracts are accounted for under one of two methods:

- Regulatory Hedges – Energy-related derivative contracts which are designated as regulatory hedges relate primarily to the Company's fuel-hedging programs, where gains and losses are initially recorded as regulatory liabilities and assets, respectively, and then are included in fuel expense as the underlying fuel is used in operations and ultimately recovered through the energy cost recovery clause.
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Not Designated – Gains and losses on energy-related derivative contracts that are not designated or fail to qualify as hedges are recognized in the statements of income as incurred.

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Some energy-related derivative contracts require physical delivery as opposed to financial settlement, and this type of derivative is both common and prevalent within the electric industry. When an energy-related derivative contract is settled physically, any cumulative unrealized gain or loss is reversed and the contract price is recognized in the respective line item representing the actual price of the underlying goods being delivered.

At December 31, 2017, the net volume of energy-related derivative contracts for natural gas positions totaled 69 million mmBtu for the Company, with the longest hedge date of 2020 over which it is hedging its exposure to the variability in future cash flows for forecasted transactions.

In addition to the volume discussed above, the Company enters into physical natural gas supply contracts that provide the option to sell back excess gas due to operational constraints. The expected volume of natural gas subject to such a feature is 5 million mmBtu.

Interest Rate Derivatives

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

At December 31, 2017, there were no interest rate derivatives outstanding.

The estimated pre-tax losses related to interest rate derivatives that will be reclassified from accumulated OCI to interest expense for the 12-month period ending December 31, 2018 are $6 million. The Company has deferred gains and losses that are expected to be amortized into earnings through 2035.

Derivative Financial Statement Presentation and Amounts

The Company enters into energy-related and interest rate derivative contracts that may contain provisions that permit intra-contract netting of derivative receivables and payables for routine billing and offsets related to events of default and settlements. 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 was reflected on the balance sheets as follows:

| | 2017 | | 2016 | |
|---|---|---|---|---|
| Derivative Category and Balance Sheet Location | Assets | Liabilities | Assets | Liabilities |
| | (in millions) | | | |
| Derivatives designated as hedging instruments for regulatory purposes | | | | |
| Energy-related derivatives: | | | | |
| Other current assets/Other current liabilities | $2 | $ 6 | $13 | $ 5 |
| Other deferred charges and assets/Other deferred credits and liabilities | 2 | 4 | 7 | 4 |
| Total derivatives designated as hedging instruments for regulatory purposes | $4 | $ 10 | $20 | $ 9 |
| Gross amounts recognized | $4 | $ 10 | $20 | $ 9 |
| Gross amounts offset | $(4) | $ (4) | $(8) | $ (8) |
| Net amounts recognized in the Balance Sheets | $— | $ 6 | $12 | $ 1 |

Energy-related derivatives not designated as hedging instruments were immaterial on the balance sheets for 2017 and 2016.

NOTES (continued)
Alabama Power Company 2017 Annual Report

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

| Derivative Category | Unrealized Losses Balance Sheet Location | 2017 | 2016 | Unrealized Gains Balance Sheet Location | 2017 | 2016 |
|---|---|---|---|---|---|---|
| | | (in millions) | | | (in millions) | |
| Energy-related derivatives: | Other regulatory assets, current | $(4) | $(1) | Other regulatory liabilities, current | $ 1 | $ 8 |
| | Other regulatory assets, deferred | (3) | — | Other regulatory liabilities, deferred | — | 4 |
| Total energy-related derivative gains (losses) | | $(7) | $(1) | | $ 1 | $ 12 |

For the years ended December 31, 2017, 2016, and 2015, the pre-tax effect of interest rate derivatives designated as cash flow hedging instruments on the statements of income was as follows:

| Derivatives in Cash Flow Hedging Relationships | Gain (Loss) Recognized in OCI on Derivative (Effective Portion) | | | Gain (Loss) Reclassified from Accumulated OCI into Income (Effective Portion) | | | |
|---|---|---|---|---|---|---|---|
| | | | | | Amount | | |
| Derivative Category | 2017 | 2016 | 2015 | Statements of Income Location | 2017 | 2016 | 2015 |
| | (in millions) | | | | (in millions) | | |
| Interest rate derivatives | $ — | $ (3) | $ (7) | Interest expense, net of amounts capitalized | $(6) | $(6) | $(3) |

There was no material ineffectiveness recorded in earnings for any period presented.
The pre-tax effect of energy-related derivatives not designated as hedging instruments on the statements of income was not material for any year presented.

Contingent Features

The Company does not have any credit arrangements that would require material changes in payment schedules or terminations as a result of a credit rating downgrade. There are certain derivatives that could require collateral, but not accelerated payment, in the event of various credit rating changes of certain affiliated companies.

At December 31, 2017, the fair value of derivative liabilities with contingent features was $1 million. However, because of joint and several liability features underlying these derivatives, the maximum potential collateral requirements arising from the credit-risk related contingent features, at a rating below BBB- and/or Baa3, were $12 million, and include certain agreements that could require collateral in the event that one or more Southern Company system power pool participants has a credit rating change to below investment grade.

Generally, collateral may be provided by a Southern Company guaranty, letter of credit, or cash. If collateral is required, fair value amounts recognized for the right to reclaim cash collateral or the obligation to return cash collateral are not offset against fair value amounts recognized for derivatives executed with the same counterparty.

The Company 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, the Company's collateral posted in these accounts was not material.

The Company is exposed to losses related to financial instruments in the event of counterparties' nonperformance. The Company only enters into agreements and material transactions with counterparties that have investment grade credit ratings by Moody's and S&P or with counterparties who have posted collateral to cover potential credit exposure. The Company has also established risk management policies and controls to determine and monitor the creditworthiness of counterparties in order to mitigate the Company's exposure to counterparty credit risk. Therefore, the Company does not anticipate a material adverse effect on the financial statements as a result of counterparty nonperformance.

NOTES (continued)
Alabama Power Company 2017 Annual Report

12. QUARTERLY FINANCIAL INFORMATION (UNAUDITED)
Summarized quarterly financial information for 2017 and 2016 is as follows:

| Quarter Ended | Operating Revenues | Operating Income | Net Income After Dividends on Preferred and Preference Stock |
|---|---|---|---|
| | (in millions) | | |
| March 2017 | $1,382 | $ 376 | $ 174 |
| June 2017 | 1,484 | 454 | 230 |
| September 2017 | 1,740 | 616 | 325 |
| December 2017 | 1,433 | 268 | 119 |
| | | | |
| March 2016 | $1,331 | $ 333 | $ 156 |
| June 2016 | 1,444 | 430 | 213 |
| September 2016 | 1,785 | 650 | 351 |
| December 2016 | 1,329 | 252 | 102 |

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

SELECTED FINANCIAL AND OPERATING DATA 2013-2017
Alabama Power Company 2017 Annual Report

| | 2017 | 2016 | 2015 | 2014 | 2013 |
|---|---|---|---|---|---|
| Operating Revenues (in millions) | $ 6,039 | $ 5,889 | $ 5,768 | $ 5,942 | $ 5,618 |
| Net Income After Dividends on Preferred and Preference Stock (in millions) | $ 848 | $ 822 | $ 785 | $ 761 | $ 712 |
| Cash Dividends on Common Stock (in millions) | $ 714 | $ 765 | $ 571 | $ 550 | $ 644 |
| Return on Average Common Equity (percent) | 12.89 | 13.34 | 13.37 | 13.52 | 13.07 |
| Total Assets (in millions)[(a)(b)] | $ 23,864 | $ 22,516 | $ 21,721 | $ 20,493 | $ 19,185 |
| Gross Property Additions (in millions) | $ 1,949 | $ 1,338 | $ 1,492 | $ 1,543 | $ 1,204 |
| Capitalization (in millions): | | | | | |
| Common stock equity | $ 6,829 | $ 6,323 | $ 5,992 | $ 5,752 | $ 5,502 |
| Preference stock | — | 196 | 196 | 343 | 343 |
| Redeemable preferred stock | 291 | 85 | 85 | 342 | 342 |
| Long-term debt[(a)] | 7,628 | 6,535 | 6,654 | 6,137 | 6,195 |
| Total (excluding amounts due within one year) | $ 14,748 | $ 13,139 | $ 12,927 | $ 12,574 | $ 12,382 |
| Capitalization Ratios (percent): | | | | | |
| Common stock equity | 46.3 | 48.1 | 46.4 | 45.8 | 44.4 |
| Preference stock | — | 1.5 | 1.5 | 2.7 | 2.8 |
| Redeemable preferred stock | 2.0 | 0.7 | 0.7 | 2.7 | 2.7 |
| Long-term debt[(a)] | 51.7 | 49.7 | 51.4 | 48.8 | 50.1 |
| Total (excluding amounts due within one year) | 100.0 | 100.0 | 100.0 | 100.0 | 100.0 |
| Customers (year-end): | | | | | |
| Residential | 1,268,271 | 1,262,752 | 1,253,875 | 1,247,061 | 1,241,998 |
| Commercial | 199,840 | 199,146 | 197,920 | 197,082 | 196,209 |
| Industrial | 6,171 | 6,090 | 6,056 | 6,032 | 5,851 |
| Other | 766 | 762 | 757 | 753 | 751 |
| Total | 1,475,048 | 1,468,750 | 1,458,608 | 1,450,928 | 1,444,809 |
| Employees (year-end) | 6,613 | 6,805 | 6,986 | 6,935 | 6,896 |

(a) A reclassification of debt issuance costs from Total Assets to Long-term debt of $40 million and $38 million is reflected for years 2014 and 2013, respectively, in accordance with new accounting standards adopted in 2015 and applied retrospectively.

(b) A reclassification of deferred tax assets from Total Assets of $20 million and $27 million is reflected for years 2014 and 2013, respectively, in accordance with new accounting standards adopted in 2015 and applied retrospectively.

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SELECTED FINANCIAL AND OPERATING DATA 2013-2017 (continued)
Alabama Power Company 2017 Annual Report

| | 2017 | 2016 | 2015 | 2014 | 2013 |
|---|---|---|---|---|---|
| Operating Revenues (in millions): | | | | | |
| Residential | $2,302 | $2,322 | $2,207 | $2,209 | $2,079 |
| Commercial | 1,649 | 1,627 | 1,564 | 1,533 | 1,477 |
| Industrial | 1,477 | 1,416 | 1,436 | 1,480 | 1,369 |
| Other | 30 | (43 ) | 27 | 27 | 27 |
| Total retail | 5,458 | 5,322 | 5,234 | 5,249 | 4,952 |
| Wholesale — non-affiliates | 276 | 283 | 241 | 281 | 248 |
| Wholesale — affiliates | 97 | 69 | 84 | 189 | 212 |
| Total revenues from sales of electricity | 5,831 | 5,674 | 5,559 | 5,719 | 5,412 |
| Other revenues | 208 | 215 | 209 | 223 | 206 |
| Total | $6,039 | $5,889 | $5,768 | $5,942 | $5,618 |
| Kilowatt-Hour Sales (in millions): | | | | | |
| Residential | 17,219 | 18,343 | 18,082 | 18,726 | 17,920 |
| Commercial | 13,606 | 14,091 | 14,102 | 14,118 | 13,892 |
| Industrial | 22,687 | 22,310 | 23,380 | 23,799 | 22,904 |
| Other | 198 | 208 | 201 | 211 | 211 |
| Total retail | 53,710 | 54,952 | 55,765 | 56,854 | 54,927 |
| Wholesale — non-affiliates | 5,415 | 5,744 | 3,567 | 3,588 | 3,711 |
| Wholesale — affiliates | 4,166 | 3,177 | 4,515 | 6,713 | 7,672 |
| Total | 63,291 | 63,873 | 63,847 | 67,155 | 66,310 |
| Average Revenue Per Kilowatt-Hour (cents): | | | | | |
| Residential | 13.37 | 12.66 | 12.21 | 11.80 | 11.60 |
| Commercial | 12.12 | 11.55 | 11.09 | 10.86 | 10.63 |
| Industrial | 6.51 | 6.35 | 6.14 | 6.22 | 5.98 |
| Total retail | 10.16 | 9.68 | 9.39 | 9.23 | 9.02 |
| Wholesale | 3.89 | 3.95 | 4.02 | 4.56 | 4.04 |
| Total sales | 9.21 | 8.88 | 8.71 | 8.52 | 8.16 |
| Residential Average Annual Kilowatt-Hour Use Per Customer | 13,601 | 14,568 | 14,454 | 15,051 | 14,451 |
| Residential Average Annual Revenue Per Customer | $1,819 | $1,844 | $1,764 | $1,775 | $1,676 |
| Plant Nameplate Capacity Ratings (year-end) (megawatts) | 11,797 | 11,797 | 11,797 | 12,222 | 12,222 |
| Maximum Peak-Hour Demand (megawatts): | | | | | |
| Winter | 10,513 | 10,282 | 12,162 | 11,761 | 9,347 |
| Summer | 10,711 | 10,932 | 11,292 | 11,054 | 10,692 |
| Annual Load Factor (percent) | 63.5 | 63.5 | 58.4 | 61.4 | 64.9 |
| Plant Availability (percent): | | | | | |
| Fossil-steam | 82.8 | 83.0 | 81.5 | 82.5 | 87.3 |
| Nuclear | 97.6 | 88.0 | 92.1 | 93.3 | 90.7 |
| Source of Energy Supply (percent): | | | | | |
| Coal | 44.8 | 47.1 | 49.1 | 49.0 | 50.0 |
| Nuclear | 22.2 | 20.3 | 21.3 | 20.7 | 20.3 |
| Hydro | 5.4 | 4.8 | 5.6 | 5.5 | 8.1 |

| | | | | | |
|---|---|---|---|---|---|
| Gas | 18.1 | 17.1 | 14.6 | 15.4 | 15.7 |
| Purchased power — | | | | | |
| From non-affiliates | 4.6 | 4.8 | 4.4 | 3.6 | 2.9 |
| From affiliates | 4.9 | 5.9 | 5.0 | 5.8 | 3.0 |
| Total | 100.0 | 100.0 | 100.0 | 100.0 | 100.0 |

GEORGIA POWER COMPANY
FINANCIAL SECTION

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MANAGEMENT'S REPORT ON INTERNAL CONTROL OVER FINANCIAL REPORTING

Georgia Power Company 2017 Annual Report

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

Under management's supervision, an evaluation of the design and effectiveness of the Company's internal control over financial reporting was conducted based on the framework in Internal Control—Integrated Framework (2013) issued by the Committee of Sponsoring Organizations of the Treadway Commission. Based on this evaluation, management concluded that the Company's internal control over financial reporting was effective as of December 31, 2017.

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

/s/ Xia Liu
Xia Liu
Executive Vice President, Chief Financial Officer, and Treasurer
February 20, 2018

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the stockholder and the Board of Directors of Georgia Power Company

Opinion on the Financial Statements

We have audited the accompanying balance sheets and statements of capitalization of Georgia Power Company (the Company) (a wholly-owned subsidiary of The Southern Company) as of December 31, 2017 and 2016, the related statements of income, comprehensive income, common stockholder's equity, and cash flows for each of the three years in the period ended December 31, 2017, and the related notes (collectively referred to as the "financial statements"). In our opinion, the financial statements (pages II-270 to II-321) 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.

Basis for Opinion

These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on the Company's financial statements 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 audit to obtain reasonable assurance about whether the financial statements are free of material misstatement, whether due to error or fraud. The Company is not required to have, nor were we engaged to perform, an audit of its internal control over financial reporting. As part of our audits, we are required to obtain an understanding of internal control over financial reporting but not for the purpose of expressing an opinion on the effectiveness of the Company's internal control over financial reporting. Accordingly, we express no such opinion. Our audits included performing procedures to assess the risks of material misstatement of the financial statements, whether due to error or fraud, and performing procedures that 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. We believe that our audits provide a reasonable basis for our opinion.

/s/ Deloitte & Touche LLP
Atlanta, Georgia
February 20, 2018

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

DEFINITIONS

| Term | Meaning |
|---|---|
| 2013 ARP | Alternative Rate Plan approved by the Georgia PSC in 2013 for Georgia Power for the years 2014 through 2016 and subsequently extended through 2019 |
| AFUDC | Allowance for funds used during construction |
| Alabama Power | Alabama Power Company |
| ARO | Asset retirement obligation |
| ASC | Accounting Standards Codification |
| ASU | Accounting Standards Update |
| Bechtel | Bechtel Power Corporation |
| CCR | Coal combustion residuals |
| Clean Air Act | Clean Air Act Amendments of 1990 |
| $CO_2$ | Carbon dioxide |
| 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 |
| CWIP | Construction work in progress |
| 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 |
| Gulf Power | Gulf Power Company |
| 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 |
| 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 |
| Mississippi Power | Mississippi Power Company |
| mmBtu | Million British thermal units |
| Moody's | Moody's Investors Service, Inc. |
| MW | Megawatt |
| NCCR | Nuclear Construction Cost Recovery |
| $NO_X$ | Nitrogen oxide |
| NRC | U.S. Nuclear Regulatory Commission |

| | |
|---|---|
| OCI | Other comprehensive income |

DEFINITIONS
(continued)

| Term | Meaning |
| --- | --- |
| power pool | The operating arrangement whereby the integrated generating resources of the traditional electric operating companies and Southern Power (excluding subsidiaries) are subject to joint commitment and dispatch in order to serve their combined load obligations |
| PPA | Power purchase agreement |
| PSC | Public Service Commission |
| PTC | Production tax credit |
| ROE | Return on equity |
| S&P | S&P Global Ratings, a division of S&P Global Inc. |
| SCS | Southern Company Services, Inc. (the Southern Company system service company) |
| SEC | U.S. Securities and Exchange Commission |
| SEGCO | Southern Electric Generating Company |
| $SO_2$ | Sulfur dioxide |
| Southern Company | The Southern Company |
| Southern Company Gas | Southern Company Gas and its subsidiaries |
| Southern Company system | Southern Company, the traditional electric operating companies, Southern Power, Southern Company Gas (as of July 1, 2016), SEGCO, Southern Nuclear, SCS, Southern Linc, PowerSecure, Inc. (as of May 9, 2016), and other subsidiaries |
| Southern Linc | Southern Communications Services, Inc. |
| Southern Nuclear | Southern Nuclear Operating Company, Inc. |
| Southern Power | Southern Power Company and its subsidiaries |
| 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 Company, 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 |

MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS
Georgia Power Company 2017 Annual Report
OVERVIEW
Business Activities
Georgia Power Company (the Company) operates as a vertically integrated utility providing electric service to retail customers within its traditional service territory located within the State of Georgia and to wholesale customers in the Southeast.
Many factors affect the opportunities, challenges, and risks of the Company's business of providing electric service. These factors include the ability to maintain a constructive regulatory environment, to maintain and grow energy sales, and to effectively manage and secure timely recovery of costs. These costs include those related to projected long-term demand growth, stringent environmental standards, reliability, fuel, capital expenditures, and restoration following major storms. The Company has various regulatory mechanisms that operate to address cost recovery. Effectively operating pursuant to these regulatory mechanisms and appropriately balancing required costs and capital expenditures with customer prices will continue to challenge the Company for the foreseeable future. The Company is required to file a base rate case with the Georgia PSC by July 1, 2019.
The Company continues to focus on several key performance indicators, including, but not limited to, customer satisfaction, plant availability, system reliability, the execution of major construction projects, and net income. The Company's financial success is directly tied to customer satisfaction. Key elements of ensuring customer satisfaction include outstanding service, high reliability, and competitive prices. Management uses customer satisfaction surveys to evaluate the Company's results and generally targets the top quartile of these surveys in measuring performance. See RESULTS OF OPERATIONS herein for information on the Company's financial performance.
Nuclear Construction
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, the Company, 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, the Company 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 the Company's recommendation to continue construction.
The Company expects Plant Vogtle Units 3 and 4 to be placed in service by November 2021 and November 2022, respectively. The Company'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)). The Company'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. The Company 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 FUTURE EARNINGS POTENTIAL – "Retail Regulatory Matters – Nuclear Construction" herein for additional information on Plant Vogtle Units 3 and 4.
Earnings

The Company's 2017 net income after dividends on preferred and preference stock was $1.4 billion, representing a $84 million, or 6.3%, increase over the previous year. The increase was due primarily to lower non-fuel operations and maintenance expenses, primarily as a result of cost containment and modernization initiatives, partially offset by lower revenues resulting from milder weather and lower customer usage as compared to 2016.

The Company's 2016 net income after dividends on preferred and preference stock was $1.3 billion, representing a $70 million, or 5.6%, increase over the previous year. The increase was due primarily to an increase in base retail revenues effective January 1,

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2016, as authorized by the Georgia PSC, the 2015 correction of a customer billing error, and higher retail revenues in the third quarter 2016 due to warmer weather as compared to the corresponding period in 2015, partially offset by an expected refund to retail customers as a result of the Company's retail ROE exceeding the retail ROE range allowed under the 2013 ARP during 2016. Higher non-fuel operating expenses also partially offset the revenue increase. See Note 1 to the financial statements under "General" and FUTURE EARNINGS POTENTIAL – "Retail Regulatory Matters – Rate Plans" herein for additional information related to the 2015 error correction and the refund to retail customers, respectively.

RESULTS OF OPERATIONS

A condensed income statement for the Company follows:

| | Amount | Increase (Decrease) from Prior Year | |
|---|---|---|---|
| | 2017 | 2017 | 2016 |
| | (in millions) | | |
| Operating revenues | $8,310 | $ (73) | $ 57 |
| Fuel | 1,671 | (136) | (226) |
| Purchased power | 1,038 | 159 | 15 |
| Other operations and maintenance | 1,653 | (307) | 116 |
| Depreciation and amortization | 895 | 40 | 9 |
| Taxes other than income taxes | 409 | 4 | 14 |
| Total operating expenses | 5,666 | (240) | (72) |
| Operating income | 2,644 | 167 | 129 |
| Interest expense, net of amounts capitalized | 419 | 31 | 25 |
| Other income (expense), net | 33 | (5) | (23) |
| Income taxes | 830 | 50 | 11 |
| Net income | 1,428 | 81 | 70 |
| Dividends on preferred and preference stock | 14 | (3) | — |
| Net income after dividends on preferred and preference stock | $1,414 | $ 84 | $ 70 |

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MANAGEMENT'S DISCUSSION AND ANALYSIS (continued)
Georgia Power Company 2017 Annual Report

Operating Revenues

Operating revenues for 2017 were $8.3 billion, reflecting a $73 million decrease from 2016. Details of operating revenues were as follows:

| | Amount | |
|---|---|---|
| | 2017 | 2016 |
| | (in millions) | |
| Retail — prior year | $7,772 | $7,727 |
| Estimated change resulting from — | | |
| Rates and pricing | 114 | 154 |
| Sales decline | (33) | (10) |
| Weather | (166) | 113 |
| Fuel cost recovery | 51 | (212) |
| Retail — current year | 7,738 | 7,772 |
| Wholesale revenues — | | |
| Non-affiliates | 163 | 175 |
| Affiliates | 26 | 42 |
| Total wholesale revenues | 189 | 217 |
| Other operating revenues | 383 | 394 |
| Total operating revenues | $8,310 | $8,383 |
| Percent change | (0.9)% | 0.7% |

Retail revenues of $7.7 billion in 2017 decreased $34 million, or 0.4%, compared to 2016. The significant factors driving this change are shown in the preceding table. The increase in rates and pricing was primarily due to an increase in revenues related to the recovery of Plant Vogtle Units 3 and 4 construction financing costs under the NCCR tariff.

Retail revenues of $7.8 billion in 2016 increased $45 million, or 0.6%, compared to 2015. The significant factors driving this change are shown in the preceding table. The increase in rates and pricing was primarily due to increases in base tariffs approved under the 2013 ARP and the NCCR tariff, all effective January 1, 2016, and the 2015 correction of a customer billing error. The increase was partially offset by an adjustment for an expected refund to retail customers as a result of the Company's retail ROE exceeding the retail ROE range allowed under the 2013 ARP during 2016.

See Note 1 to the financial statements under "General" for additional information on the customer billing error correction and Note 3 to the financial statements under "Retail Regulatory Matters – Rate Plans" and " – Nuclear Construction" for additional information on the rate changes. 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 include provisions to adjust billings for fluctuations in fuel costs, including the energy component of purchased power costs. Under these fuel cost recovery provisions, fuel revenues generally equal fuel expenses and do not affect net income. See FUTURE EARNINGS POTENTIAL – "Retail Regulatory Matters – Fuel Cost Recovery" herein for additional information.

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

| | 2017 | 2016 | 2015 |
|---|---|---|---|
| | (in millions) | | |
| Capacity and other | $67 | $72 | $108 |
| Energy | 96 | 103 | 107 |
| Total non-affiliated | $163 | $175 | $215 |

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

Wholesale revenues from sales to non-affiliates will vary depending on fuel prices, the market prices of wholesale energy compared to the cost of the Company's and the Southern Company system's generation, demand for energy within the Southern Company system's electric service territory, and the availability of the Southern Company system's generation. Increases and decreases in energy revenues

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that are driven by fuel prices are accompanied by an increase or decrease in fuel costs and do not have a significant impact on net income. Short-term opportunity sales are made at market-based rates that generally provide a margin above the Company's variable cost of energy.

Wholesale revenues from non-affiliated sales decreased $12 million, or 6.9%, in 2017 as compared to 2016 and decreased $40 million, or 18.6%, in 2016 as compared to 2015. The decrease in 2017 was related to decreases of $5 million in capacity revenues and $7 million in energy revenues. The decrease in 2016 was related to decreases of $36 million in capacity revenues and $4 million in energy revenues. The decreases in capacity revenues reflect the expiration of wholesale contracts in the first and second quarters of 2016. The decrease in capacity revenues in 2016 also reflects the retirement of 14 coal-fired generating units since March 31, 2015 as a result of the Company's environmental compliance strategy. The decrease in energy revenues in 2017 was primarily due to lower demand and the effects of the expired contracts. The decrease in energy revenues in 2016 was primarily due to lower fuel prices. See FUTURE EARNINGS POTENTIAL – "Environmental Matters – Environmental Laws and Regulations – Air Quality" herein for additional information regarding the Company's environmental compliance strategy.

Wholesale revenues from sales to affiliated companies will vary depending on demand and the availability and cost of generating resources at each company. These affiliate sales are made in accordance with the Intercompany Interchange Contract (IIC), as approved by the FERC. These transactions do not have a significant impact on earnings since this energy is generally sold at marginal cost. In 2017, wholesale revenues from sales to affiliates decreased $16 million as compared to 2016 due to a 42.8% decrease in KWH sales as a result of the lower market cost of available energy compared to the cost of Company-owned generation. In 2016, wholesale revenues from sales to affiliates increased $22 million as compared to 2015 due to a 153.5% increase in KWH sales as a result of the lower cost of Company-owned generation compared to the market cost of available energy, partially offset by lower coal and natural gas prices.

Other operating revenues decreased $11 million, or 2.8%, in 2017 from the prior year 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, and a $14 million adjustment in 2016 for customer temporary facilities services revenues, partially offset by a $13 million increase in outdoor lighting sales revenues due to increased sales in new and replacement markets, primarily attributable to LED conversions.

Other operating revenues increased $30 million, or 8.2%, in 2016 from the prior year primarily due to a $14 million increase related to customer temporary facilities services revenues and a $12 million increase in outdoor lighting revenues due to increased sales in new and replacement markets, primarily attributable to 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 2017 (in billions) | Total KWH Percent Change 2017 | Total KWH Percent Change 2016 | Weather-Adjusted Percent Change 2017 | Weather-Adjusted Percent Change 2016 |
|---|---|---|---|---|---|
| Residential | 26.1 | (5.2 )% | 3.5 % | (0.2 )% | 1.0 % |
| Commercial | 32.2 | (2.4 ) | 0.7 | (0.9 ) | (1.0 ) |
| Industrial | 23.5 | (1.0 ) | (0.2 ) | (0.1 ) | (0.9 ) |
| Other | 0.6 | (4.2 ) | (3.5 ) | (4.0 ) | (3.5 ) |
| Total retail | 82.4 | (2.9 ) | 1.3 | (0.4 )% | (0.4 )% |
| Wholesale | | | | | |
| Non-affiliates | 3.3 | (4.0 ) | (2.5 ) | | |
| Affiliates | 0.8 | (42.8) | 153.5 | | |
| Total wholesale | 4.1 | (15.3) | 18.8 | | |

| | | | |
|---|---|---|---|
| Total energy sales | 86.5 | (3.6 )% | 2.1 % |

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

In 2017, KWH sales for the residential class decreased 5.2% compared to 2016 primarily due to milder weather in 2017. Weather-adjusted residential KWH sales decreased by 0.2% primarily due to a decline in average customer usage resulting from an increase in multi-family housing and energy saving initiatives, partially offset by customer growth. Weather-adjusted commercial KWH sales decreased by 0.9% primarily due to a decline in average customer usage resulting from an increase in electronic commerce transactions and energy saving initiatives, partially offset by customer growth. Weather-adjusted industrial KWH sales were essentially flat primarily due to decreased demand in the chemicals and paper sectors, offset by increased demand in the textile, non-manufacturing, and rubber sectors. Additionally, Hurricane Irma negatively impacted customer usage for all customer classes for the period.

In 2016, KWH sales for the residential class increased 3.5% compared to 2015 primarily due to warmer weather in the third quarter 2016 as compared to the corresponding period in 2015 and increased customer growth, partially offset by decreased customer usage. Weather-adjusted residential KWH sales increased by 1.0% primarily due to an increase of approximately 28,000 residential customers since December 31, 2015, partially offset by a decline in customer usage primarily resulting from an increase in multi-family housing and efficiency improvements in residential appliances and lighting. Weather-adjusted commercial KWH sales decreased by 1.0% primarily due to a decline in average customer usage resulting from an increase in electronic commerce transactions and energy saving initiatives, partially offset by an increase of approximately 2,600 commercial customers since December 31, 2015. Weather-adjusted industrial KWH sales decreased 0.9% primarily due to decreased demand in the pipeline, primary metals, stone, clay, and glass, and textile sectors, partially offset by increased demand in the non-manufacturing sector.

See "Operating Revenues" above for a discussion of significant changes in wholesale sales to non-affiliates and affiliated companies.

Fuel and Purchased Power Expenses

Fuel costs constitute one of the largest expenses for the Company. The mix of fuel sources for generation of electricity is determined primarily by demand, the unit cost of fuel consumed, and the availability of generating units. Additionally, the Company purchases a portion of its electricity needs from the wholesale market.

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

| | 2017 | 2016 | 2015 |
|---|---|---|---|
| Total generation (in billions of KWHs) | 63.2 | 68.4 | 65.9 |
| Total purchased power (in billions of KWHs) | 26.9 | 24.8 | 25.6 |
| Sources of generation (percent) — | | | |
| Gas | 41 | 38 | 39 |
| Coal | 32 | 36 | 34 |
| Nuclear | 25 | 24 | 25 |
| Hydro | 2 | 2 | 2 |
| Cost of fuel, generated (in cents per net KWH) — | | | |
| Gas | 2.68 | 2.36 | 2.47 |
| Coal | 3.17 | 3.28 | 4.55 |
| Nuclear | 0.83 | 0.85 | 0.78 |
| Average cost of fuel, generated (in cents per net KWH) | 2.36 | 2.33 | 2.77 |
| Average cost of purchased power (in cents per net KWH)(*) | 4.62 | 4.53 | 4.33 |

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

Fuel and purchased power expenses were $2.7 billion in 2017, an increase of $23 million, or 0.9%, compared to 2016. The increase was primarily due to an $84 million increase in the average cost of fuel and purchased power primarily related to higher natural gas prices, partially offset by a net decrease of $61 million related to the volume of KWHs generated and purchased primarily due to milder weather, resulting in lower customer demand.

Fuel and purchased power expenses were $2.7 billion in 2016, a decrease of $211 million, or 7.3%, compared to 2015. The decrease was primarily due to a $285 million net decrease in the average cost of fuel and purchased power due to lower coal and natural gas prices, partially offset by a $74 million net increase in the volume of KWHs generated and purchased to meet customer demand.

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Fuel and purchased power energy transactions do not have a significant impact on earnings since these fuel expenses are generally offset by fuel revenues through the Company's fuel cost recovery mechanism. See FUTURE EARNINGS POTENTIAL – "Retail Regulatory Matters – Fuel Cost Recovery" herein for additional information.

Fuel

Fuel expense was $1.7 billion in 2017, a decrease of $136 million, or 7.5%, compared to 2016. The decrease was primarily due to a decrease of 7.7% in the volume of KWHs generated largely due to milder weather, resulting in lower customer demand, partially offset by an increase of 13.6% in the average cost of natural gas per KWH generated. Fuel expense was $1.8 billion in 2016, a decrease of $226 million, or 11.1%, compared to 2015. The decrease was primarily due to a decrease of 18.6% in the average cost of coal and natural gas per KWH generated, partially offset by an increase of 10.0% in the volume of KWHs generated by coal.

Purchased Power - Non-Affiliates

Purchased power expense from non-affiliates was $416 million in 2017, an increase of $55 million, or 15.2%, compared to 2016. The increase was primarily due to a 13.4% increase in the volume of KWHs purchased primarily due to unplanned outages at Company-owned generating units. Purchased power expense from non-affiliates was $361 million in 2016, an increase of $72 million, or 24.9%, compared to 2015. The increase was primarily due to a 36.8% increase in the volume of KWHs purchased to meet customer demand, partially offset by a 12.5% decrease in the average cost per KWH purchased due to lower natural gas prices.

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

Purchased Power - Affiliates

Purchased power expense from affiliates was $622 million in 2017, an increase of $104 million, or 20.1%, compared to 2016. The increase was primarily due to a 7.0% increase in the volume of KWHs purchased to support Southern Company system transmission reliability and as a result of unplanned outages at Company-owned generating units and a 1.8% increase in the average cost per KWH purchased primarily resulting from higher natural gas prices. Purchased power expense from affiliates was $518 million in 2016, a decrease of $57 million, or 9.9%, compared to 2015. The decrease was primarily due to an 11.9% decrease in the volume of KWHs purchased due to the lower market cost of available energy as compared to Southern Company system resources, partially offset by a 6.2% increase in the average cost per KWH purchased.

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

Other Operations and Maintenance Expenses

In 2017, other operations and maintenance expenses decreased $307 million, or 15.7%, compared to 2016. The decrease was primarily due to cost containment and modernization activities implemented in the third quarter 2016 that contributed to decreases of $85 million in generation maintenance costs, $49 million in employee benefits, $46 million in transmission and distribution overhead line maintenance, and $22 million in customer accounts and sales costs. Other factors include a $40 million increase in gains from sales of assets, a $19 million decrease in scheduled generation outage costs, and a $15 million decrease in customer assistance expenses, primarily in demand-side management costs related to the timing of new programs.

In 2016, other operations and maintenance expenses increased $116 million, or 6.3%, compared to 2015. The increase was primarily due to a $37 million decrease in gains from sales of assets, a $36 million charge in connection with cost containment activities, a $30 million increase in overhead line maintenance, a $15 million increase in hydro and gas generation maintenance, a $10 million increase in customer accounts, service, and sales costs, and a $7 million increase in material costs related to higher generation volumes. The increase was partially offset by a decrease of $36 million in pension costs.

See FUTURE EARNINGS POTENTIAL – "Other Matters" herein and Note 2 to the financial statements for additional information related to the cost containment and modernization activities and pension costs, respectively.

Depreciation and Amortization

Depreciation and amortization increased $40 million, or 4.7%, in 2017 compared to 2016. The increase was primarily due to a $33 million increase related to additional plant in service and a $14 million decrease in amortization of regulatory liabilities

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related to other cost of removal obligations that expired in December 2016, partially offset by a $9 million decrease in depreciation related to generating unit retirements in 2016 and amortization of regulatory assets related to certain cancelled environmental and fuel conversion projects that expired in December 2016.

Depreciation and amortization increased $9 million, or 1.1%, in 2016 compared to 2015. The increase was primarily due to a $34 million increase related to additional plant in service and a $9 million increase in other cost of removal, partially offset by an $18 million decrease related to amortization of certain nuclear construction financing costs that was completed in December 2015 and a decrease of $16 million related to unit retirements.

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

Taxes Other Than Income Taxes

In 2017, taxes other than income taxes increased $4 million, or 1.0%, compared to 2016. In 2016, taxes other than income taxes increased $14 million, or 3.6%, compared to 2015 primarily due to increases of $7 million in property taxes as a result of an increase in the assessed value of property and $4 million in payroll taxes.

Interest Expense, Net of Amounts Capitalized

In 2017, interest expense, net of amounts capitalized increased $31 million, or 8.0%, compared to the prior year primarily due to an increase in outstanding borrowings.

In 2016, interest expense, net of amounts capitalized increased $25 million, or 6.9%, compared to the prior year. The increase was primarily due to a $34 million increase in interest due to additional long-term borrowings from the FFB and higher interest rates on obligations for pollution control revenue bonds remarketed in 2015, partially offset by an increase of $4 million in AFUDC debt.

Other Income (Expense), Net

In 2017, other income (expense), net decreased $5 million compared to the prior year primarily due to a $10 million increase in donations and an $8 million decrease in AFUDC equity resulting from higher short-term borrowings, partially offset by a $7 million increase in third party infrastructure services revenue and a $6 million increase in wholesale operating fee revenue associated with contractual targets.

In 2016, other income (expense), net decreased $23 million compared to the prior year primarily due to decreases of $8 million in customer contributions in aid of construction, $6 million in wholesale operating fee revenue associated with contractual targets, and $4 million in gains on purchases of state tax credits.

Income Taxes

Income taxes increased $50 million, or 6.4%, in 2017 compared to the prior year primarily due to higher pre-tax earnings, partially offset by an adjustment related to Tax Reform Legislation. See FUTURE EARNINGS POTENTIAL – "Income Tax Matters – Federal Tax Reform Legislation" herein and Note 5 to the financial statements for additional information.

Income taxes increased $11 million, or 1.4%, in 2016 compared to the prior year primarily due to higher pre-tax earnings, partially offset by decreases in non-deductible book depreciation and increased state investment tax credits.

Dividends on Preferred and Preference Stock

Dividends on preferred and preference stock decreased $3 million, or 17.6%, in 2017 compared to the prior year due to the redemption in October 2017 of all outstanding shares of the Company's preferred and preference stock. See Note 6 to the financial statements under "Outstanding Classes of Capital Stock" for additional information.

Effects of Inflation

The Company is subject to rate regulation that is generally based on the recovery of historical and projected costs. The effects of inflation can create an economic loss since the recovery of costs could be in dollars that have less purchasing power. Any adverse effect of inflation on the Company's results of operations has not been substantial in recent years.

FUTURE EARNINGS POTENTIAL

General

The Company operates as a vertically integrated utility providing electric service to retail customers within its traditional service territory located in the State of Georgia and to wholesale customers in the Southeast. Prices for electricity provided by the

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Company to retail customers are set by the Georgia PSC under cost-based regulatory principles. Prices for wholesale electricity sales, interconnecting transmission lines, and the exchange of electric power are regulated by the FERC. Retail rates and earnings are reviewed and may be adjusted periodically within certain limitations. See ACCOUNTING POLICIES – "Application of Critical Accounting Policies and Estimates – Utility Regulation" herein and Note 3 to the financial statements under "Retail Regulatory Matters" for additional information about regulatory matters.

The results of operations for the past three years are not necessarily indicative of future earnings potential. The level of the Company's future earnings depends on numerous factors that affect the opportunities, challenges, and risks of the Company's business of providing electric service. These factors include the Company's ability to maintain a constructive regulatory environment that continues to allow for the timely recovery of prudently-incurred costs during a time of increasing costs and limited projected demand growth over the next several years. Plant Vogtle Units 3 and 4 construction and rate recovery are also major factors. Future earnings will be driven primarily by customer growth. Earnings will also depend upon maintaining and growing sales, considering, among other things, the adoption and/or penetration rates of increasingly energy-efficient technologies, increasing volumes of electronic commerce transactions, and higher multi-family home construction, all of which could contribute to a net reduction in customer usage. Earnings are subject to a variety of other factors. These factors include weather, competition, new energy contracts with other utilities, energy conservation practiced by customers, the use of alternative energy sources by customers, the price of electricity, the price elasticity of demand, and the rate of economic growth or decline in the Company's service territory. Demand for electricity is primarily driven by the pace of economic growth that may be affected by changes in regional and global economic conditions, which may impact future earnings.

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 under "Retail Regulatory Matters – Rate Plans" and "Current and Deferred Income Taxes," respectively, for additional information.

Environmental Matters

The Company'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 Company 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 Company's 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. The Company's Environmental Compliance Cost Recovery (ECCR) tariff allows for the recovery of capital and operations and maintenance costs related to environmental controls mandated by state and federal regulations. Further, increased costs that are recovered through regulated rates could contribute to reduced demand for electricity, which could negatively affect results of operations, cash flows, and financial condition. 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.

Through 2017, the Company has invested approximately $5.5 billion in environmental capital retrofit projects to comply with environmental requirements, with annual totals of approximately $0.3 billion, $0.2 billion, and $0.3 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 Company's current compliance strategy estimates capital expenditures of $1.2 billion from 2018 through 2022, with annual totals of approximately $0.5 billion, $0.1 billion, $0.2 billion, $0.2 billion, and $0.2 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 Company 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

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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 Company's 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 Company-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 Company has fossil fuel-fired generation 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. Georgia's seasonal $NO_X$ budget remains unchanged. 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 the 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 Georgia and Alabama) 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 Company. The EPA has not yet responded to the SIP revisions proposed by the State of Georgia.

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 Company's 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.

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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 and distribution 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 the Company's CCR units, and has requested that the EPA approve its state permitting program.

Based on cost estimates for closure and monitoring of ash ponds pursuant to the CCR Rule, the Company recorded an update to the AROs for each CCR unit in 2015. As further analysis is performed and closure details are developed, the Company 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 the Company's AROs as of December 31, 2017.

Environmental Remediation

The Company 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 Company may also incur substantial costs to clean up affected sites. The Company conducts studies to determine the extent of any required cleanup and has recognized 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 Company may be liable for some or all required cleanup costs for additional sites that may require environmental remediation. See Notes 1 and 3 to the financial statements under "Environmental Remediation Recovery" and "Environmental Matters – Environmental Remediation," respectively, for additional information.

Global Climate Issues

In 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.
The EPA's GHG reporting rule requires annual reporting of GHG emissions expressed in terms of metric tons of $CO_2$ equivalent emissions for a company's operational control of facilities. Based on ownership or financial control of facilities, the Company's

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2016 GHG emissions were approximately 33 million metric tons of $CO_2$ equivalent. The preliminary estimate of the Company's 2017 GHG emissions on the same basis is approximately 30 million metric tons of $CO_2$ equivalent.

FERC Matters

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

In December 2016, the traditional electric operating companies (including the Company) and Southern Power filed an amendment to their market-based rate tariff that proposed certain changes to the energy auction, as well as several non-tariff changes. On February 2, 2017, the FERC issued an order accepting all such changes subject to an additional condition of cost-based price caps for certain sales outside of the energy auction, finding that all of these changes would provide adequate alternative mitigation for the traditional electric operating companies' (including the Company's) and Southern Power's potential to exert market power in certain areas served by the traditional electric operating companies (including the Company) and in some adjacent areas. On May 17, 2017, the FERC accepted the traditional electric operating companies' (including the Company's) 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' (including the Company's) and Southern Power's June 29, 2017 triennial updated market power analysis. The FERC directed the traditional electric operating companies (including the Company) 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 (including the Company) 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.

Retail Regulatory Matters

The Company's revenues from regulated retail operations are collected through various rate mechanisms subject to the oversight of the Georgia PSC. The Company currently recovers its costs from the regulated retail business through the 2013 ARP, which includes traditional base tariff rates, Demand-Side Management (DSM) tariffs, ECCR tariffs, and Municipal Franchise Fee (MFF) tariffs. In addition, financing costs 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 "Retail Regulatory Matters" for additional information.

On January 16, 2018, the Georgia PSC approved the Company's sale of its natural gas lateral pipeline serving Plant McDonough Units 4 through 6 to Southern Natural Gas, L.L.C. (SNG) at net book value. Pursuant to this approval, legal transfer of the lateral pipeline is expected to occur in the fourth quarter 2018 and payment of $142 million is expected to occur in the first quarter 2020. Completion of this sale is contingent on certain conditions to be satisfied by SNG that include, among other things, expansion of the existing lateral pipeline. Southern Company Gas, an affiliate of the Company, owns a 50% equity interest in SNG. The ultimate outcome of this matter cannot be determined at this time; however, no material impact on the Company's financial statements is expected.

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 the Company will be required to file its next base rate case by July 1, 2019. Furthermore, through December 31, 2019, the Company and Atlanta

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Gas Light Company each will retain their respective merger savings, net of transition costs, as defined in the settlement agreement; through December 31, 2022, such net merger savings applicable to each will be shared on a 60/40 basis with their respective customers; thereafter, all merger savings will be retained by customers. See Note 3 to the financial statements under "Retail Regulatory Matters – Rate Plans" for additional information regarding the 2013 ARP.

In accordance with the 2013 ARP, the Georgia PSC approved increases to tariffs effective January 1, 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, the Company's retail ROE is set at 10.95% and earnings are evaluated against a retail ROE range of 10.00% to 12.00%. Two-thirds of any earnings above 12.00% will be directly refunded to customers, with the remaining one-third retained by the Company. There will be no recovery of any earnings shortfall below 10.00% on an actual basis. In 2015, the Company's retail ROE was within the allowed retail ROE range. In 2016, the Company's retail ROE exceeded 12.00%, and the Company will refund to retail customers approximately $44 million in 2018, as approved by the Georgia PSC on January 16, 2018. In 2017, the Company'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, the Company is required to submit its analysis of the Tax Reform Legislation and related recommendations to address the related impacts on the Company'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 the Company'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 the Company sold its 33% ownership interest in the Intercession City unit to Duke Energy Florida, LLC.

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

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

The Georgia PSC also approved the Renewable Energy Development Initiative (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 the Company was approved, as well as consideration for no more than 200 MWs of capacity as part of a renewable commercial and industrial program.

In 2017, the Company 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. The Company 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 the Company'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 rate case.

Fuel Cost Recovery

The Company has established fuel cost recovery rates approved by the Georgia PSC. In 2015, the Georgia PSC approved the Company's request to lower annual billings by approximately $350 million effective January 1, 2016. In May 2016, the Georgia PSC approved the Company's request to further lower annual billings under an interim fuel rider by approximately $313 million

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effective June 1, 2016, which expired on December 31, 2017. The Georgia PSC will review the Company's cumulative over or under recovered fuel balance no later than September 1, 2018 and evaluate the need to file a fuel case unless the Company deems it necessary to file a fuel case at an earlier time. The Company 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.

The Company's fuel cost recovery mechanism includes costs associated with a natural gas hedging program, as revised and approved by the Georgia PSC, allowing the use of an array of derivative instruments within a 48-month time horizon.

Fuel cost recovery revenues as recorded on the financial statements are adjusted for differences in actual recoverable fuel costs and amounts billed in current regulated rates. Accordingly, changes in the billing factor will not have a significant effect on the Company's revenues or net income, but will affect cash flow.

Storm Damage Recovery

The Company 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 the Company's transmission and distribution facilities during September 2017 and October 2016, respectively. The incremental restoration costs related to these hurricanes deferred in the regulatory asset for storm damage totaled approximately $260 million. At December 31, 2017, the total balance in the regulatory asset related to storm damage was $333 million. The rate of storm damage cost recovery is expected to be adjusted as part of the Company'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 the Company's financial statements. See Note 1 to the financial statements under "Storm Damage Recovery" for additional information regarding the Company's storm damage reserve.

Nuclear Construction

Vogtle 3 and 4 Agreement and EPC Contractor Bankruptcy

In 2008, the Company, 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. The Company, 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, the Company 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 the Company'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, the Company, 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 the Company, the other Vogtle Owners, and certain affiliates of MEAG Power against Westinghouse, and the Company and the other Vogtle Owners surrendered the Westinghouse Letters of Credit.

Additionally, on June 9, 2017, the Company, 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, the Company, 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 the Company and the DOE, the Company 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 the Company determines that any of the Company'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 the Company or Southern Nuclear for any action or inaction in connection with their performance as agent for the Vogtle Owners is limited to removal of the Company 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 the Company to recover financing costs for nuclear construction projects certified by the Georgia PSC. Financing costs are recovered on all applicable certified costs through annual adjustments to the NCCR tariff up to the certified capital cost of $4.418 billion. As of December 31, 2017, the Company had recovered approximately $1.6 billion of financing costs. On January 30, 2018, the Company 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.

The Company 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 the Company 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 the Company.

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

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(and issued its related order on January 11, 2018) certain recommendations made by the Company 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) the Company 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 the Company'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 the Company'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 the Company'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 the Company'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 the Company's seventeenth VCM report are based do not materialize, both the Company 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. The Company believes the appeal has no merit; however, an adverse outcome in this appeal could have a material impact on the 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 the Company'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. The Company 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. The Company'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.

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Cost and Schedule

The Company'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.

The Company 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, the Company 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 the Company, 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 the Company 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.

Regulated utility businesses 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, net operating losses (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 Southern Company's 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 $8 million, a $150 million decrease in regulatory assets, and a $3.1 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.

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 the Georgia PSC. On January 31, 2018, SCS, on behalf of the traditional electric operating companies (including the Company), filed with the FERC a reduction to the Company's open access transmission tariff charge for 2018 to reflect the revised federal corporate tax rate. See Note 3 to the financial statements under "Regulatory Matters" for additional information regarding the Company's rate filing to reflect the impacts of the Tax Reform Legislation.

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 $270 million for the 2017 tax year and approximately $120 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. See Note 5 to the financial statements under "Current and Deferred Income Taxes" for additional information.

Other Matters

The Company is involved in various other matters being litigated and regulatory matters that could affect future earnings. In addition, the Company is subject to certain claims and legal actions arising in the ordinary course of business. The Company's business activities are subject to extensive governmental regulation related to public health and the environment, such as regulation of air emissions and water discharges. Litigation over environmental issues and claims of various types, including property damage, personal injury, common law nuisance, and citizen enforcement of environmental requirements, such as 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 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 the Company's financial statements. See Note 3 to the financial statements for a discussion of various other contingencies, regulatory matters, and other matters being litigated which may affect future earnings potential.

The Company regularly reviews its business to transform and modernize. Primarily in response to changing customer expectations and payment patterns, including electronic payments and alternative payment locations, and ongoing efforts to increase overall operating efficiencies, in 2017, the Company initiated the closure of its remaining payment offices and an employee attrition plan affecting approximately 300 positions. Charges associated with these activities did not have a material impact on the Company's results of operations, financial position, or cash flows. The efficiencies gained are expected to place downward pressure on operating costs in 2018.

ACCOUNTING POLICIES

Application of Critical Accounting Policies and Estimates

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

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Utility Regulation

The Company is subject to retail regulation by the Georgia PSC and wholesale regulation by the FERC. These regulatory agencies set the rates the Company is permitted to charge customers based on allowable costs. As a result, the Company applies accounting standards which require the financial statements to reflect the effects of rate regulation. Through the ratemaking process, the regulators may require the inclusion of costs or revenues in periods different than when they would be recognized by a non-regulated company. This treatment may result in the deferral of expenses and the recording of related regulatory assets based on anticipated future recovery through rates or the deferral of gains or creation of liabilities and the recording of related regulatory liabilities. The application of the accounting standards has a further effect on the Company's financial statements as a result of the estimates of allowable costs used in the ratemaking process. These estimates may differ from those actually incurred by the Company; therefore, the accounting estimates inherent in specific costs such as depreciation, AROs, and pension and other postretirement benefits have less of a direct impact on the Company's results of operations and financial condition than they would on a non-regulated company.

As reflected in Note 1 to the financial statements, significant regulatory assets and liabilities have been recorded. Management reviews the ultimate recoverability of these regulatory assets and any requirement to refund these regulatory liabilities based on applicable regulatory guidelines and GAAP. However, adverse legislative, judicial, or regulatory actions could materially impact the amounts of such regulatory assets and liabilities and could adversely impact the Company's financial statements.

Federal Tax Reform Legislation

Following the enactment of 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, the Company considers all amounts recorded in the financial statements as a result of Tax Reform Legislation to be "provisional" as discussed in SAB 118 and subject to revision. The Company is awaiting additional guidance from industry and income tax authorities in order to finalize its accounting. The ultimate impact of 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 "Retail Regulatory Matters – Rate Plans" 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 the decommissioning of the Company's nuclear facilities, which include the Company's ownership interests in Plant Hatch and Plant Vogtle Units 1 and 2, and facilities that are subject to the CCR Rule, principally ash ponds. In addition, the Company has retirement obligations related to various landfill sites, underground storage tanks, and asbestos removal. The Company also has identified retirement obligations related to certain transmission and distribution facilities, including the disposal of polychlorinated biphenyls in certain transformers; leasehold improvements; equipment on customer property; and property associated with the Company's rail lines and natural gas pipelines. However, liabilities for the removal of these assets have not been recorded because the settlement timing for the retirement obligations related to these assets is indeterminable and, therefore, the fair value of the retirement obligations cannot be reasonably estimated. A liability for these AROs will be recognized

when sufficient information becomes available to support a reasonable estimation of the ARO.
The Company previously recorded AROs as a result of state requirements in Georgia which closely align with the requirements of the CCR Rule discussed above. The cost estimates are based on information using various assumptions related to closure and post-closure costs, timing of future cash outlays, inflation and discount rates, and the potential methods for complying with the CCR Rule requirements for closure. As further analysis is performed and closure details are developed, the Company 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, the Company considers the liabilities for AROs to be critical accounting estimates.

Pension and Other Postretirement Benefits

The Company's calculation of pension and other postretirement benefits expense is dependent on a number of assumptions. These assumptions include discount rates, healthcare cost trend rates, expected long-term return on plan assets, mortality rates, expected salary and wage increases, and other factors. Components of pension and other postretirement benefits expense include interest and service cost on the pension and other postretirement benefit plans, expected return on plan assets, and amortization of certain unrecognized costs and obligations. Actual results that differ from the assumptions utilized are accumulated and amortized over future periods and, therefore, generally affect recognized expense and the recorded obligation in future periods. While the Company believes that the assumptions used are appropriate, differences in actual experience or significant changes in assumptions would affect its pension and other postretirement benefits costs and obligations.

Key elements in determining the Company's pension and other postretirement benefit expense are the expected long-term return on plan assets and the discount rate used to measure the benefit plan obligations and the periodic benefit plan expense for future periods. The expected long-term return on pension and other postretirement benefit plan assets is based on the Company's investment strategy, historical experience, and expectations for long-term rates of return that consider external actuarial advice. The Company determines the long-term return on plan assets by applying the long-term rate of expected returns on various asset classes to the Company's target asset allocation. For purposes of determining its liability related to the pension and other postretirement benefit plans, the Company discounts the future related cash flows using a single-point discount rate for each plan developed from the weighted average of market-observed yields for high quality fixed income securities with maturities that correspond to expected benefit payments. For 2015 and prior years, the Company computed the interest cost component of its net periodic pension and other postretirement benefit plan expense using the same single-point discount rate. Beginning in 2016, the Company adopted a full yield curve approach for calculating the interest cost component whereby the discount rate for each year is applied to the liability for that specific year. As a result, the interest cost component of net periodic pension and other postretirement benefit plan expense decreased by approximately $35 million in 2016.

A 25 basis point change in any significant assumption (discount rate, salaries, or long-term return on plan assets) would result in an $11 million or less change in total annual benefit expense and a $172 million or less change in projected obligations.

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

Contingent Obligations

The Company is subject to a number of federal and state laws and regulations, as well as other factors and conditions that subject it to environmental, litigation, and other risks. See FUTURE EARNINGS POTENTIAL herein and Note 3 to the financial statements for more information regarding certain of these contingencies. The Company periodically evaluates its exposure to such risks and records reserves for those matters where a non-tax-related loss is considered probable and reasonably estimable. The adequacy of reserves can be significantly affected by external events or conditions that can be unpredictable; thus, the ultimate outcome of such matters could materially affect the Company's results of operations, cash flows, or financial condition.

Recently Issued Accounting Standards

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 the Company's revenue, including energy provided to customers, is from tariff offerings that provide electricity without a defined contractual term, as well as longer-term contractual commitments, including PPAs.
The 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 energy-related derivatives, are excluded from the scope of ASC 606 and, therefore, will be accounted for and disclosed separately from revenues under ASC 606. The 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.

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The new standard is effective for reporting periods beginning after December 15, 2017. The Company applied the modified retrospective method of adoption effective January 1, 2018. The 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. ASU 2016-02 is effective for fiscal years beginning after December 15, 2018 and the Company will adopt the new standard effective January 1, 2019.

The 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, the 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 PPAs and cellular towers where the Company is the lessee and to outdoor lighting where the Company is the lessor. The Company is currently analyzing pole attachment agreements, and a lease determination has not been made at this time. While the Company has not yet determined the ultimate impact, adoption of ASU 2016-02 is expected to have a significant impact on the Company's balance sheet.

Other

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 the 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. The 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. The Company adopted ASU 2017-12 effective January 1, 2018 with no material impact on its financial statements.

FINANCIAL CONDITION AND LIQUIDITY

Overview

The Company's financial condition remained stable at December 31, 2017. The Company's cash requirements primarily consist of funding ongoing operations, common stock dividends, capital expenditures, and debt maturities. Capital expenditures and other investing activities include investments to build new generation facilities, including Plant Vogtle Units 3 and 4, to maintain existing generation facilities, to comply with environmental regulations including adding environmental modifications to existing generating units, to expand and improve transmission and distribution facilities, and for restoration following major storms. Operating cash flows provide a substantial portion of the Company's cash needs. For the three-year period from 2018 through 2020, the Company's projected common stock dividends, capital expenditures, and debt maturities are expected to exceed operating cash flows. The Company plans to finance future cash needs in excess of its operating cash flows primarily through

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external securities issuances, equity contributions from Southern Company, borrowings from financial institutions, and borrowings through the FFB. The Company plans to use commercial paper to manage seasonal variations in operating cash flows and for other working capital needs. The Company intends to continue to monitor its access to short-term and long-term capital markets as well as bank credit arrangements to meet future capital and liquidity needs. See "Sources of Capital," "Financing Activities," and "Capital Requirements and Contractual Obligations" herein for additional information.

The Company's investments in the qualified pension plan and nuclear decommissioning trust funds increased in value as of December 31, 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 plan are anticipated during 2018. The Company also funded approximately $5 million to its nuclear decommissioning trust funds in 2017. See "Contractual Obligations" herein and Notes 1 and 2 to the financial statements under "Nuclear Decommissioning" and "Pension Plans," respectively, for additional information.

Net cash provided from operating activities totaled $1.9 billion in 2017, a decrease of $513 million from 2016, primarily due to the timing of vendor payments and increases in under-recovered fuel costs and prepaid federal income taxes, partially offset by a decrease in voluntary contributions to the qualified pension plan. Net cash provided from operating activities totaled $2.4 billion in 2016, a decrease of $92 million from 2015, primarily due to the voluntary contribution to the qualified pension plan in 2016, partially offset by the timing of vendor payments. See FUTURE EARNINGS POTENTIAL – "Income Tax Matters – Federal Tax Reform Legislation" herein and Note 5 to the financial statements for additional information regarding federal income taxes.

Net cash used for investing activities totaled $0.9 billion, $2.3 billion, and $1.9 billion in 2017, 2016, and 2015, respectively, due to gross property additions primarily related to installation of equipment to comply with environmental standards; construction of generation, transmission, and distribution facilities including Plant Vogtle Units 3 and 4, partially offset in 2017 by $1.7 billion in payments received under the Guarantee Settlement Agreement; and purchases of nuclear fuel. The majority of funds needed for gross property additions for the last several years has been provided from operating activities, capital contributions from Southern Company, and the issuance of debt. See FUTURE EARNINGS POTENTIAL – "Retail Regulatory Matters – Nuclear Construction" herein for additional information on the Guarantee Settlement Agreement and construction of Plant Vogtle Units 3 and 4.

Net cash used for financing activities totaled $151 million, $142 million, and $530 million for 2017, 2016, and 2015, respectively. The increase in cash used in 2017 compared to 2016 was primarily due to a decrease in notes payable, a decrease in borrowings from the FFB for construction of Plant Vogtle Units 3 and 4, and the redemption of all outstanding shares of the Company's preferred and preference stock, partially offset by higher issuances of senior notes and junior subordinated notes and a decrease in maturities of senior notes. The decrease in cash used in 2016 compared to 2015 was primarily due to higher capital contributions from Southern Company, a decrease in redemptions and maturities of senior notes, and an increase in short-term debt, partially offset by higher common stock dividends and a decrease in borrowings from the FFB for construction of Plant Vogtle Units 3 and 4. 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 an increase of $3.1 billion in deferred credits related to income taxes and a decrease of $2.8 billion in accumulated deferred income taxes primarily resulting from the impacts of Tax Reform Legislation; an increase in property, plant, and equipment of $2.0 billion to comply with environmental standards and the construction of generation, transmission, and distribution facilities, partially offset by payments received under the Guarantee Settlement Agreement of $1.7 billion, net of joint owner portion; and an increase of $1.2 billion in long-term debt primarily due to issuances of senior notes and junior subordinated notes. See FUTURE EARNINGS POTENTIAL – "Income Tax Matters – Federal Tax Reform Legislation" herein and Note 5 to the financial statements for additional information on Tax Reform Legislation and Note 3 to the financial statements under "Retail Regulatory Matters – Nuclear Construction" for additional information on the Guarantee Settlement Agreement.

The Company's ratio of common equity to total capitalization plus short-term debt was 49.7% at December 31, 2017 and 50.0% at December 31, 2016. See Note 6 to the financial statements for additional information.

Sources of Capital

The Company plans to obtain the funds required for construction and other purposes from sources similar to those used in the past, which were primarily from operating cash flows, external security issuances, borrowings from financial institutions, equity contributions from Southern Company, and borrowings from the FFB. However, the amount, type, and timing of any future financings, if needed, will depend upon regulatory approvals, prevailing market conditions, and other factors.

In 2014, the Company entered into the Loan Guarantee Agreement with the DOE, under which the proceeds of borrowings may be used to reimburse the Company for Eligible Project Costs incurred in connection with its construction of Plant Vogtle Units 3

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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 the Company under a multi-advance credit facility (FFB Credit Facility) among the Company, the DOE, and the FFB. As of December 31, 2017, the Company had borrowed $2.6 billion under the FFB Credit Facility. On July 27, 2017, the Company 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 the Company 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 "Retail Regulatory Matters – Nuclear Construction" for additional information regarding Plant Vogtle Units 3 and 4.

The issuance of long-term securities by the Company is subject to the approval of the Georgia PSC. In addition, the issuance of short-term debt securities by the Company is subject to regulatory approval by the FERC. Additionally, with respect to the public offering of securities, the Company files registration statements with the SEC under the Securities Act of 1933, as amended. The amounts of securities authorized by the Georgia PSC and the FERC are continuously monitored and appropriate filings are made to ensure flexibility in the capital markets.

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

At December 31, 2017, the Company's current liabilities exceeded current assets by $521 million. The Company's current liabilities frequently exceed current assets because of scheduled maturities of long-term debt and the periodic use of short-term debt as a funding source, as well as significant seasonal fluctuations in cash needs.

The Company intends to utilize operating cash flows, external security issuances, borrowings from financial institutions, equity contributions from Southern Company, and borrowings from the FFB to fund its short-term capital needs. The Company has substantial cash flow from operating activities and access to the capital markets and financial institutions to meet short-term liquidity needs.

At December 31, 2017, the Company had approximately $852 million of cash and cash equivalents. A committed credit arrangement with banks at December 31, 2017 was $1.75 billion of which $1.73 billion was unused. In May 2017, the Company amended its multi-year credit arrangement which, among other things, extended the maturity date from 2020 to 2022.

This bank credit arrangement, as well as the Company's term loan arrangements, contains a covenant that limits debt levels and contains a cross-acceleration provision to other indebtedness (including guarantee obligations) of the Company. Such cross-acceleration provision to other indebtedness would trigger an event of default if the Company defaulted on indebtedness, the payment of which was then accelerated. At December 31, 2017, the Company was in compliance with this covenant. This bank credit arrangement does not contain a material adverse change clause at the time of borrowing.

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

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

A portion of the unused credit with banks is allocated to provide liquidity support to the Company's pollution control revenue bonds and commercial paper program. The amount of variable rate pollution control revenue bonds outstanding requiring liquidity support as of December 31, 2017 was $550 million as compared to $868 million at December 31, 2016. In addition, at December 31, 2017, the Company had $469 million of pollution control revenue bonds outstanding that were required to be remarketed within the next 12 months.

The Company may also meet short-term cash needs through a Southern Company subsidiary organized to issue and sell commercial paper at the request and for the benefit of the Company and the other traditional electric operating companies. Proceeds from such issuances for the benefit of the Company are loaned directly to the Company. The obligations of each

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traditional electric operating company under these arrangements are several and there is no cross-affiliate credit support. Short-term borrowings are included in notes payable in the balance sheets.
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 | $ — | — % | $ 135 | 1.3 % | $ 760 |
| Short-term bank debt | 150 | 2.2 % | 292 | 2.0 % | 800 |
| Total | $ 150 | 2.2 % | $ 427 | 1.8 % | |
| December 31, 2016: | | | | | |
| Commercial paper | $ 392 | 1.1 % | $ 87 | 0.8 % | $ 443 |
| December 31, 2015: | | | | | |
| Commercial paper | $ 158 | 0.6 % | $ 234 | 0.3 % | $ 678 |
| Short-term bank debt | — | — % | 62 | 0.8 % | 250 |
| Total | $ 158 | 0.6 % | $ 296 | 0.4 % | |

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

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

Financing Activities

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

Senior Notes

In March 2017, the Company issued $450 million aggregate principal amount of Series 2017A 2.00% Senior Notes due March 30, 2020 and $400 million aggregate principal amount of Series 2017B 3.25% Senior Notes due March 30, 2027. The proceeds were used to repay a portion of the Company's short-term indebtedness and for general corporate purposes, including the Company's continuous construction program.

In June 2017, the Company repaid at maturity $450 million aggregate principal amount of Series 2007B 5.70% Senior Notes.

In August 2017, the Company issued $500 million aggregate principal amount of Series 2017C 2.00% Senior Notes due September 8, 2020. The proceeds were used to repay the Company's $50 million short-term floating rate bank loan due December 1, 2017 and outstanding commercial paper borrowings and for general corporate purposes.

Junior Subordinated Notes

In September 2017, the Company 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 the Company's 6.125% Series Class A Preferred Stock and 2.25 million shares ($225 million aggregate liquidation amount) of the Company's 6.50% Series 2007A Preference Stock.

Pollution Control Revenue Bonds

In April 2017, the Company purchased and held $27 million aggregate principal amount of Development Authority of Burke County (Georgia) Pollution Control Revenue Bonds (Georgia Power Company Plant Vogtle Project), Fifth Series 1995. In October 2017, the Company remarketed these bonds to the public.

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In August 2017, the Company purchased and held $38 million aggregate principal amount of Development Authority of Bartow County (Georgia) Pollution Control Revenue Bonds (Georgia Power Company Plant Bowen Project), First Series 1997. In October 2017, the Company remarketed these bonds to the public.

Other

In June 2017, the Company entered into three floating rate bank loans in aggregate principal amounts of $50 million, $150 million, and $100 million, with maturity dates of December 1, 2017, May 31, 2018, and June 28, 2018, respectively, bearing interest based on one-month LIBOR. Also in June 2017, the Company borrowed $500 million pursuant to a short-term uncommitted bank credit arrangement, which bears interest at a rate agreed upon by the Company and the bank from time to time and is payable on no less than 30 days' demand by the bank. The proceeds from these bank loans were used to repay a portion of the Company's existing indebtedness and for working capital and other general corporate purposes, including the Company's continuous construction program.

In August 2017, the Company repaid $250 million of the $500 million aggregate principal amount outstanding pursuant to its uncommitted bank credit arrangement. Also in August 2017, the Company amended its $100 million floating rate bank loan to extend the maturity date from June 28, 2018 to October 26, 2018.

In December 2017, the Company repaid the remaining $250 million aggregate principal amount outstanding pursuant to its uncommitted bank credit arrangement.

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

Credit Rating Risk

At December 31, 2017, the Company did not have any credit arrangements that would require material changes in payment schedules or terminations as a result of a credit rating downgrade.

There are certain contracts that could require collateral, but not accelerated payment, in the event of a credit rating change to BBB- and/or Baa3 or below. These contracts are for physical electricity purchases and sales, fuel purchases, fuel transportation and storage, energy price risk management, transmission, 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 Baa3 | $ 87 |
| Below BBB- and/or Baa3 | $ 1,055 |

Included in these amounts are certain agreements that could require collateral in the event that the Company or Alabama Power has a credit rating change to below investment grade. Generally, collateral may be provided by a Southern Company guaranty, letter of credit, or cash. Additionally, a credit rating downgrade could impact the ability of the Company to access capital markets and would be likely to impact the cost at which it does so.

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

On March 24, 2017, S&P revised its consolidated credit rating outlook for Southern Company and its subsidiaries (including the Company) from stable to negative.

On March 30, 2017, Fitch placed the ratings of the Company on rating watch negative.

While it is unclear how the credit rating agencies, the FERC, and the Georgia PSC 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, including the Company, may be negatively impacted. Absent actions by Southern Company and its subsidiaries, including the Company, to mitigate the resulting impacts, which, among other alternatives, could include adjusting capital structure and/or monetizing regulatory assets, the

Company's credit ratings could be negatively affected. See Note 3 to the financial statements under "Retail Regulatory Matters – Rate Plans" for additional information.

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Market Price Risk
Due to cost-based rate regulation and other various cost recovery mechanisms, the Company continues to have limited exposure to market volatility in interest rates, commodity fuel prices, and prices of electricity. To manage the volatility attributable to these exposures, the Company nets the exposures, where possible, to take advantage of natural offsets and enters into various derivative transactions for the remaining exposures pursuant to the Company's policies in areas such as counterparty exposure and risk management practices. The Company's policy is that derivatives are to be used primarily for hedging purposes and mandates strict adherence to all applicable risk management policies. Derivative positions are monitored using techniques including, but not limited to, market valuation, value at risk, stress testing, and sensitivity analysis.
To mitigate future exposure to changes in interest rates, the Company may enter into derivatives designated as hedges. The weighted average interest rate on $1.9 billion of long-term variable interest rate exposure at December 31, 2017 was 2.66%. If the Company sustained a 100 basis point change in interest rates for all long-term variable interest rate exposure, the change would affect annualized interest expense by approximately $19 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.
To mitigate residual risks relative to movements in electricity prices, the Company enters into physical fixed-price contracts for the purchase and sale of electricity through the wholesale electricity market and, to a lesser extent, financial hedge contracts for natural gas purchases. The Company continues to manage a fuel-hedging program implemented per the guidelines of the Georgia PSC. The Company had no material change in market risk exposure for the year ended December 31, 2017 when compared to the December 31, 2016 reporting period.
The changes in fair value of energy-related derivative contracts are substantially attributable to both the volume and the price of natural gas. For the years ended December 31, the changes in fair value of energy-related derivative contracts, the majority of which are composed of regulatory hedges, were as follows:

| | 2017 Changes | 2016 Changes |
|---|---|---|
| | Fair Value | |
| | (in millions) | |
| Contracts outstanding at the beginning of the period, assets (liabilities), net | $36 | $ (13 ) |
| Contracts realized or settled: | | |
| Swaps realized or settled | (13 ) | (2 ) |
| Options realized or settled | (1 ) | 11 |
| Current period changes(*): | | |
| Swaps | (28 ) | 31 |
| Options | (7 ) | 9 |
| Contracts outstanding at the end of the period, assets (liabilities), net | $(13) | $ 36 |

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

The net hedge volumes of energy-related derivative contracts for the years ended December 31 were as follows:

| | 2017 | 2016 |
|---|---|---|
| | mmBtu Volume | |
| | (in millions) | |
| Commodity – Natural gas swaps | 146 | 128 |
| Commodity – Natural gas options | 17 | 27 |
| Total hedge volume | 163 | 155 |

The weighted average swap contract cost above market prices was approximately $0.08 per mmBtu as of December 31, 2017. The weighted average swap contract cost below market prices was approximately $0.23 per mmBtu as of December 31, 2016. The change in option fair value is primarily attributable to the volatility of the market and the underlying change in the natural gas price. All natural gas hedge gains and losses are recovered through the Company's fuel cost recovery mechanism.

At December 31, 2017 and 2016, substantially all of the Company's energy-related derivative contracts were designated as regulatory hedges and were related to the Company's fuel-hedging program, which had a time horizon up to 48 months. Hedging

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gains and losses are initially recorded as regulatory liabilities and assets, respectively, and then are included in fuel expense as they are recovered through the fuel cost recovery mechanism. Gains and losses on energy-related derivative contracts that are not designated or fail to qualify as hedges are recognized in the statements of income as incurred and were not material for any year presented.

The Company uses over-the-counter contracts that are not exchange traded but are fair valued using prices which are market observable, and thus fall into Level 2 of the fair value hierarchy. See Note 10 to the financial statements for further discussion of fair value measurements. The maturities of the energy-related derivative contracts, which are all Level 2 of the fair value hierarchy, at December 31, 2017 were as follows:

| | Fair Value Measurements December 31, 2017 | | |
|---|---|---|---|
| | Total | Maturity | |
| | Fair Value | Year 1 | Years 2&3 |
| | (in millions) | | |
| Level 1 | $ — | $ — | $ — |
| Level 2 | (13) | (7) | (6) |
| Level 3 | — | — | — |
| Fair value of contracts outstanding at end of period | $ (13) | $ (7) | $ (6) |

The Company is exposed to market price risk in the event of nonperformance by counterparties to the energy-related and interest rate derivative contracts. The Company only enters into agreements and material transactions with counterparties that have investment grade credit ratings by Moody's and S&P or with counterparties who have posted collateral to cover potential credit exposure. Therefore, the Company does not anticipate market risk exposure from nonperformance by the counterparties. For additional information, see Note 1 to the financial statements under "Financial Instruments" and Note 11 to the financial statements.

Capital Requirements and Contractual Obligations

The construction program of the Company is currently estimated to total $3.3 billion for 2018, $3.2 billion for 2019, $2.7 billion for 2020, $2.4 billion for 2021, and $2.2 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. 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 $0.5 billion, $0.1 billion, $0.2 billion, $0.2 billion, and $0.2 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 Company also anticipates costs associated with closure and monitoring of ash ponds in accordance with the CCR Rule, which are reflected in the Company's ARO liabilities. These costs, which could change as the Company continues to refine its assumptions underlying the cost estimates and evaluate the method and timing of compliance activities, are estimated to be $0.2 billion per year for 2018 through 2020 and $0.3 billion per year for 2021 and 2022. See Note 1 to the financial statements under "Asset Retirement Obligations and Other Costs of Removal" for additional information.

The construction program is subject to periodic review and revision, and actual construction costs may vary from these estimates because of numerous factors. These factors include: changes in business conditions; changes in load projections; changes in environmental laws and regulations; the outcome of any legal challenges to environmental rules; changes in generating plants, including unit retirements and replacements and adding or changing fuel sources at existing generating units, to meet regulatory requirements; changes in FERC rules and regulations; Georgia PSC approvals; changes in the expected environmental compliance program; changes in legislation; the cost and efficiency of construction labor, equipment, and materials; project scope and design changes; storm impacts; and the cost of capital. In addition, there can be no assurance that costs related to capital expenditures will be fully recovered. The construction program also includes Plant Vogtle Units 3 and 4, which may be subject to revised cost 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 "Retail Regulatory Matters – Nuclear Construction" for information regarding additional factors that may impact construction expenditures.

As a result of requirements by the NRC, the Company has established external trust funds for nuclear decommissioning costs. For additional information, see Note 1 to the financial statements under "Nuclear Decommissioning."

In addition, as discussed in Note 2 to the financial statements, the Company provides postretirement benefits to substantially all employees and funds trusts to the extent required by the Georgia PSC and the FERC.

Other funding requirements related to obligations associated with scheduled maturities of long-term debt, as well as the related interest, derivative obligations, leases, other purchase commitments, and trusts are detailed in the contractual obligations table that follows. See Notes 1, 2, 6, 7, and 11 to the financial statements for additional information.

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Contractual Obligations

Contractual obligations at December 31, 2017 were as follows:

| | 2018 | 2019-2020 | 2021-2022 | After 2022 | Total |
|---|---|---|---|---|---|
| | (in millions) | | | | |
| Long-term debt[(a)] — | | | | | |
| Principal | $850 | $1,494 | $879 | $8,693 | $11,916 |
| Interest | 419 | 760 | 688 | 5,786 | 7,653 |
| Financial derivative obligations[(b)] | 10 | 10 | — | — | 20 |
| Operating leases[(c)] | 24 | 42 | 31 | 44 | 141 |
| Capital leases[(c)] | 9 | 16 | — | — | 25 |
| Purchase commitments — | | | | | |
| Capital[(d)] | 3,080 | 5,508 | 4,006 | — | 12,594 |
| Fuel[(e)] | 1,238 | 1,245 | 818 | 5,075 | 8,376 |
| Purchased power[(f)] | 318 | 545 | 549 | 2,352 | 3,764 |
| Other[(g)] | 50 | 198 | 70 | 297 | 615 |
| Trusts — | | | | | |
| Nuclear decommissioning[(h)] | 5 | 11 | 11 | 94 | 121 |
| Pension and other postretirement benefit plans[(i)] | 47 | 87 | | | 134 |
| Total | $6,050 | $9,916 | $7,052 | $22,341 | $45,359 |

(a) All amounts are reflected based on final maturity dates except for amounts related to FFB borrowings. As it relates to the FFB borrowings, the final maturity date is February 20, 2044; however, principal amortization is reflected beginning in 2020. See Note 6 to the financial statements under "DOE Loan Guarantee Borrowings" for additional information. The Company plans to continue, when economically feasible, to retire higher-cost securities and replace these obligations with lower-cost capital if market conditions permit. Variable rate interest obligations are estimated based on rates as of 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) See Notes 1 and 11 to the financial statements.

(c) Excludes PPAs that are accounted for as leases and included in "Purchased power." See Note 7 to the financial statements under "Operating Leases" for additional information.

(d) The Company provides estimated capital expenditures for a five-year period, including capital expenditures associated with environmental regulations. These amounts exclude contractual purchase commitments for nuclear fuel and capital expenditures covered under 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" and "Retail Regulatory Matters – Nuclear Construction" herein for additional information.

(e) 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.

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

(g) Includes LTSAs and contracts for the procurement of limestone. LTSAs include price escalation based on inflation indices.

(h) Projections of nuclear decommissioning trust fund contributions for Plant Hatch and Plant Vogtle Units 1 and 2 are based on the 2013 ARP. See Note 1 to the financial statements under "Nuclear Decommissioning" for additional information.

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

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MANAGEMENT'S DISCUSSION AND ANALYSIS (continued)
Georgia Power Company 2017 Annual Report

Cautionary Statement Regarding Forward-Looking Statements

The Company's 2017 Annual Report contains forward-looking statements. Forward-looking statements include, among other things, statements concerning regulated rates, customer and sales growth, economic conditions, fuel and environmental cost recovery and other rate actions, current and proposed environmental regulations and related compliance plans and estimated expenditures, pending or potential litigation matters, access to sources of capital, projections for the qualified pension plan, postretirement benefit plans, and nuclear decommissioning trust fund contributions, financing activities, completion dates of construction projects, filings with state and federal regulatory authorities, impacts of the Tax Reform Legislation, federal income tax benefits, estimated sales and purchases under power sale and purchase agreements, and estimated construction and other plans and expenditures. In some cases, forward-looking statements can be identified by terminology such as "may," "will," "could," "should," "expects," "plans," "anticipates," "believes," "estimates," "projects," "predicts," "potential," or "continue" or the negative of these terms or other similar terminology. There are various factors that could cause actual results to differ materially from those suggested by the forward-looking statements; accordingly, there can be no assurance that such indicated results will be realized. These factors include:

- the impact of recent and future federal and state regulatory changes, including environmental laws 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 Company is 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 Company;
- 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 Company operates;
- variations in demand for electricity, 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 fuels;
- effects of inflation;
- the ability to control costs and avoid cost overruns during the development, construction, and operation of facilities, which include the development and construction of generating facilities with designs that have not been 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 Company's employee and retiree benefit plans and nuclear decommissioning trust funds;
- advances in technology;
- state and federal rate regulations and the impact of pending and future rate cases and negotiations, including rate cases related to fuel and other cost recovery mechanisms;
- the ability to successfully operate generating, transmission, and distribution facilities and the successful performance of necessary corporate functions;
-

- legal proceedings and regulatory approvals and actions related to Plant Vogtle Units 3 and 4, including Georgia PSC approvals and NRC actions;
- the inherent risks involved in operating and constructing nuclear generating facilities, including environmental, health, regulatory, natural disaster, terrorism, and financial risks;
- internal restructuring or other restructuring options that may be pursued;
- potential business strategies, including acquisitions or dispositions of assets or businesses, which cannot be assured to be completed or beneficial to the Company;
- the ability of counterparties of the Company to make payments as and when due and to perform as required;

- the ability to obtain new short- and long-term contracts with wholesale customers;
- the direct or indirect effect on the Company's business resulting from cyber intrusion or physical attack and the threat of physical attacks;
- interest rate fluctuations and financial market conditions and the results of financing efforts;
- changes in the Company's credit ratings, including impacts on interest rates, access to capital markets, and collateral requirements;
- the impacts of any sovereign financial issues, including impacts on interest rates, access to capital markets, impacts on foreign currency exchange rates, counterparty performance, and the economy in general, as well as potential impacts on the benefits of the DOE loan guarantees;
- the ability of the Company to obtain additional generating capacity (or sell excess generating capacity) at competitive prices;
- catastrophic events such as fires, earthquakes, explosions, floods, tornadoes, hurricanes and other storms, droughts, pandemic health events such as influenzas, or other similar occurrences;
- the direct or indirect effects on the Company's business resulting from incidents affecting the U.S. electric grid or operation of generating resources;
- the effect of accounting pronouncements issued periodically by standard-setting bodies; and
- other factors discussed elsewhere herein and in other reports filed by the Company from time to time with the SEC.

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

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STATEMENTS OF INCOME
For the Years Ended December 31, 2017, 2016, and 2015
Georgia Power Company 2017 Annual Report

| | 2017 | 2016 | 2015 |
|---|---|---|---|
| | (in millions) | | |
| Operating Revenues: | | | |
| Retail revenues | $7,738 | $7,772 | $7,727 |
| Wholesale revenues, non-affiliates | 163 | 175 | 215 |
| Wholesale revenues, affiliates | 26 | 42 | 20 |
| Other revenues | 383 | 394 | 364 |
| Total operating revenues | 8,310 | 8,383 | 8,326 |
| Operating Expenses: | | | |
| Fuel | 1,671 | 1,807 | 2,033 |
| Purchased power, non-affiliates | 416 | 361 | 289 |
| Purchased power, affiliates | 622 | 518 | 575 |
| Other operations and maintenance | 1,653 | 1,960 | 1,844 |
| Depreciation and amortization | 895 | 855 | 846 |
| Taxes other than income taxes | 409 | 405 | 391 |
| Total operating expenses | 5,666 | 5,906 | 5,978 |
| Operating Income | 2,644 | 2,477 | 2,348 |
| Other Income and (Expense): | | | |
| Interest expense, net of amounts capitalized | (419) | (388) | (363) |
| Other income (expense), net | 33 | 38 | 61 |
| Total other income and (expense) | (386) | (350) | (302) |
| Earnings Before Income Taxes | 2,258 | 2,127 | 2,046 |
| Income taxes | 830 | 780 | 769 |
| Net Income | 1,428 | 1,347 | 1,277 |
| Dividends on Preferred and Preference Stock | 14 | 17 | 17 |
| Net Income After Dividends on Preferred and Preference Stock | $1,414 | $1,330 | $1,260 |

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

STATEMENTS OF COMPREHENSIVE INCOME
For the Years Ended December 31, 2017, 2016, and 2015
Georgia Power Company 2017 Annual Report

| | 2017 | 2016 | 2015 |
|---|---|---|---|
| | (in millions) | | |
| Net Income | $1,428 | $1,347 | $1,277 |
| Other comprehensive income (loss): | | | |
| Qualifying hedges: | | | |
| Changes in fair value, net of tax of $-, $-, and $(6), respectively | — | — | (9) |
| Reclassification adjustment for amounts included in net income, net of tax of $1, $2, and $1, respectively | 3 | 2 | 2 |
| Total other comprehensive income (loss) | 3 | 2 | (7) |
| Comprehensive Income | $1,431 | $1,349 | $1,270 |

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

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STATEMENTS OF CASH FLOWS
For the Years Ended December 31, 2017, 2016, and 2015
Georgia Power Company 2017 Annual Report

| | 2017 | 2016 | 2015 |
|---|---|---|---|
| | (in millions) | | |
| Operating Activities: | | | |
| Net income | $1,428 | $1,347 | $1,277 |
| Adjustments to reconcile net income to net cash provided from operating activities — | | | |
| Depreciation and amortization, total | 1,100 | 1,063 | 1,029 |
| Deferred income taxes | 458 | 383 | 173 |
| Retail fuel cost over recovery — long-term | — | — | 106 |
| Pension, postretirement, and other employee benefits | (68) | (33) | 40 |
| Pension and postretirement funding | — | (287) | (7) |
| Settlement of asset retirement obligations | (120) | (123) | (29) |
| Other deferred charges — affiliated | — | (111) | — |
| Other, net | (83) | (25) | (70) |
| Changes in certain current assets and liabilities — | | | |
| -Receivables | (256) | 60 | 187 |
| -Fossil fuel stock | (16) | 104 | 37 |
| -Prepaid income taxes | (168) | — | 89 |
| -Other current assets | (28) | (38) | (62) |
| -Accounts payable | (219) | (42) | (259) |
| -Accrued taxes | 1 | 131 | 25 |
| -Retail fuel cost over recovery | (84) | (32) | 10 |
| -Other current liabilities | (33) | 28 | (29) |
| Net cash provided from operating activities | 1,912 | 2,425 | 2,517 |
| Investing Activities: | | | |
| Property additions | (2,704) | (2,223) | (2,091) |
| Proceeds pursuant to the Toshiba Guarantee, net of joint owner portion | 1,682 | — | — |
| Nuclear decommissioning trust fund purchases | (574) | (808) | (985) |
| Nuclear decommissioning trust fund sales | 568 | 803 | 980 |
| Cost of removal, net of salvage | (100) | (83) | (71) |
| Change in construction payables, net of joint owner portion | 223 | (35) | 217 |
| Payments pursuant to LTSAs | (64) | (34) | (66) |
| Sale of property | 96 | 10 | 70 |
| Other investing activities | (39) | 23 | 2 |
| Net cash used for investing activities | (912) | (2,347) | (1,944) |
| Financing Activities: | | | |
| Increase (decrease) in notes payable, net | (391) | 234 | 2 |
| Proceeds — | | | |
| Senior notes | 1,350 | 650 | 500 |
| FFB loan | — | 425 | 1,000 |
| Pollution control revenue bonds issuances and remarketings | 65 | — | 409 |
| Capital contributions from parent company | 431 | 594 | 62 |
| Short-term borrowings | 700 | — | 250 |
| Other long-term debt | 370 | — | — |
| Redemptions and repurchases — | | | |

| | | | |
|---|---|---|---|
| Senior notes | (450 ) | (700 ) | (1,175 ) |
| Preferred and preference stock | (270 ) | — | — |
| Pollution control revenue bonds | (65 ) | (4 ) | (268 ) |
| Short-term borrowings | (550 ) | — | (250 ) |
| Payment of common stock dividends | (1,281 ) | (1,305 ) | (1,034 ) |
| Other financing activities | (60 ) | (36 ) | (26 ) |
| Net cash used for financing activities | (151 ) | (142 ) | (530 ) |
| Net Change in Cash and Cash Equivalents | 849 | (64 ) | 43 |
| Cash and Cash Equivalents at Beginning of Year | 3 | 67 | 24 |
| Cash and Cash Equivalents at End of Year | $852 | $3 | $67 |
| Supplemental Cash Flow Information: | | | |
| Cash paid during the period for — | | | |
| Interest (net of $23, $20, and $16 capitalized, respectively) | $386 | $375 | $353 |
| Income taxes (net of refunds) | 496 | 170 | 506 |
| Noncash transactions — | | | |
| Accrued property additions at year-end | 550 | 336 | 387 |
| Capital lease obligation | — | — | 149 |

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

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BALANCE SHEETS
At December 31, 2017 and 2016
Georgia Power Company 2017 Annual Report

| Assets | 2017 | 2016 |
|---|---|---|
| | (in millions) | |
| Current Assets: | | |
| Cash and cash equivalents | $852 | $3 |
| Receivables — | | |
| Customer accounts receivable | 708 | 523 |
| Unbilled revenues | 255 | 224 |
| Joint owner accounts receivable | 262 | 57 |
| Affiliated | 24 | 18 |
| Other accounts and notes receivable | 76 | 81 |
| Accumulated provision for uncollectible accounts | (3) | (3) |
| Fossil fuel stock | 314 | 298 |
| Materials and supplies | 504 | 479 |
| Prepaid expenses | 216 | 105 |
| Other regulatory assets, current | 205 | 193 |
| Other current assets | 15 | 38 |
| Total current assets | 3,428 | 2,016 |
| Property, Plant, and Equipment: | | |
| In service | 34,861 | 33,841 |
| Less: Accumulated provision for depreciation | 11,704 | 11,317 |
| Plant in service, net of depreciation | 23,157 | 22,524 |
| Nuclear fuel, at amortized cost | 544 | 569 |
| Construction work in progress | 4,613 | 4,939 |
| Total property, plant, and equipment | 28,314 | 28,032 |
| Other Property and Investments: | | |
| Equity investments in unconsolidated subsidiaries | 53 | 60 |
| Nuclear decommissioning trusts, at fair value | 929 | 814 |
| Miscellaneous property and investments | 59 | 46 |
| Total other property and investments | 1,041 | 920 |
| Deferred Charges and Other Assets: | | |
| Deferred charges related to income taxes | 516 | 676 |
| Other regulatory assets, deferred | 2,932 | 2,774 |
| Other deferred charges and assets | 548 | 417 |
| Total deferred charges and other assets | 3,996 | 3,867 |
| Total Assets | $36,779 | $34,835 |

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

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BALANCE SHEETS
At December 31, 2017 and 2016
Georgia Power Company 2017 Annual Report

| Liabilities and Stockholder's Equity | 2017 | 2016 |
|---|---|---|
| | (in millions) | |
| Current Liabilities: | | |
| Securities due within one year | $857 | $460 |
| Notes payable | 150 | 391 |
| Accounts payable — | | |
| Affiliated | 493 | 438 |
| Other | 834 | 589 |
| Customer deposits | 270 | 265 |
| Accrued taxes — | | |
| Accrued income taxes | — | 17 |
| Other accrued taxes | 344 | 390 |
| Accrued interest | 123 | 106 |
| Accrued compensation | 219 | 224 |
| Asset retirement obligations, current | 270 | 299 |
| Other regulatory liabilities, current | 191 | 31 |
| Over recovered fuel clause revenues, current | — | 84 |
| Other current liabilities | 198 | 182 |
| Total current liabilities | 3,949 | 3,476 |
| Long-Term Debt (See accompanying statements) | 11,073 | 10,225 |
| Deferred Credits and Other Liabilities: | | |
| Accumulated deferred income taxes | 3,175 | 6,000 |
| Deferred credits related to income taxes | 3,248 | 121 |
| Accumulated deferred ITCs | 248 | 256 |
| Employee benefit obligations | 659 | 703 |
| Asset retirement obligations, deferred | 2,368 | 2,233 |
| Other deferred credits and liabilities | 128 | 199 |
| Total deferred credits and other liabilities | 9,826 | 9,512 |
| Total Liabilities | 24,848 | 23,213 |
| Preferred Stock (See accompanying statements) | — | 45 |
| Preference Stock (See accompanying statements) | — | 221 |
| Common Stockholder's Equity (See accompanying statements) | 11,931 | 11,356 |
| Total Liabilities and Stockholder's Equity | $36,779 | $34,835 |
| Commitments and Contingent Matters (See notes) | | |

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

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STATEMENTS OF CAPITALIZATION
At December 31, 2017 and 2016
Georgia Power Company 2017 Annual Report

| | 2017 | 2016 | 2017 | 2016 |
|---|---|---|---|---|
| | (in millions) | | (percent of total) | |
| Long-Term Debt: | | | | |
| Long-term notes payable — | | | | |
| 5.70% due 2017 | $— | $450 | | |
| 1.95% to 5.40% due 2018 | 747 | 748 | | |
| 4.25% due 2019 | 499 | 500 | | |
| 2.00% due 2020 | 950 | — | | |
| 2.40% due 2021 | 325 | 325 | | |
| 2.85% due 2022 | 400 | 400 | | |
| 3.25% to 5.95% due 2023-2043 | 4,175 | 3,775 | | |
| Variable rate (2.29% at 12/31/17) due 2018 | 100 | — | | |
| Total long-term notes payable | 7,196 | 6,198 | | |
| Other long-term debt — | | | | |
| Pollution control revenue bonds — | | | | |
| 2.35% due 2022 | 53 | 53 | | |
| 1.38% to 4.00% due 2025-2049 | 940 | 900 | | |
| Variable rate (1.84% at 12/31/17) due 2022 | 13 | 13 | | |
| Variable rates (1.59% to 1.88% at 12/31/17) due 2026-2053 | 815 | 854 | | |
| 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 2023-2044 | 2,493 | 2,493 | | |
| Junior subordinated note (5.00%) due 2077 | 270 | — | | |
| Total other long-term debt | 4,716 | 4,445 | | |
| Capitalized lease obligations | 154 | 169 | | |
| Unamortized debt premium (discount), net | (12) | (10) | | |
| Unamortized debt issuance expense | (124) | (117) | | |
| Total long-term debt (annual interest requirement — $437 million) | 11,930 | 10,685 | | |
| Less amount due within one year | 857 | 460 | | |
| Long-term debt excluding amount due within one year | 11,073 | 10,225 | 48.1 % | 46.8 % |
| Preferred and Preference Stock: | | | | |
| Non-cumulative preferred stock | | | | |
| $25 par value — 6.125% | | | | |
| Authorized — 50,000,000 shares | | | | |
| Outstanding — 2017: no shares | | | | |
| — 2016: 1,800,000 shares | — | 45 | | |
| Non-cumulative preference stock | | | | |
| $100 par value — 6.50% | | | | |
| Authorized — 15,000,000 shares | | | | |
| Outstanding — 2017: no shares | | | | |
| — 2016: 2,250,000 shares | — | 221 | | |
| Total preferred and preference stock | — | 266 | — | 1.2 |
| Common Stockholder's Equity: | | | | |

| | | | | |
|---|---|---|---|---|
| Common stock, without par value — | | | | |
| Authorized — 20,000,000 shares | | | | |
| Outstanding — 9,261,500 shares | 398 | 398 | | |
| Paid-in capital | 7,328 | 6,885 | | |
| Retained earnings | 4,215 | 4,086 | | |
| Accumulated other comprehensive loss | (10) | (13) | | |
| Total common stockholder's equity | 11,931 | 11,356 | 51.9 | 52.0 |
| Total Capitalization | $23,004 | $21,847 | 100.0% | 100.0% |

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

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STATEMENTS OF COMMON STOCKHOLDER'S EQUITY
For the Years Ended December 31, 2017, 2016, and 2015
Georgia Power Company 2017 Annual Report

| | Number of Common Shares Issued | Common Stock | Paid-In Capital | Retained Earnings | Accumulated Other Comprehensive Income (Loss) | Total |
|---|---|---|---|---|---|---|
| | (in millions) | | | | | |
| Balance at December 31, 2014 | 9 | $ 398 | $ 6,196 | $ 3,835 | $ (8) | $ 10,421 |
| Net income after dividends on preferred and preference stock | — | — | — | 1,260 | — | 1,260 |
| Capital contributions from parent company | — | — | 79 | — | — | 79 |
| Other comprehensive income (loss) | — | — | — | — | (7) | (7) |
| Cash dividends on common stock | — | — | — | (1,034) | — | (1,034) |
| Balance at December 31, 2015 | 9 | 398 | 6,275 | 4,061 | (15) | 10,719 |
| Net income after dividends on preferred and preference stock | — | — | — | 1,330 | — | 1,330 |
| Capital contributions from parent company | — | — | 610 | — | — | 610 |
| Other comprehensive income (loss) | — | — | — | — | 2 | 2 |
| Cash dividends on common stock | — | — | — | (1,305) | — | (1,305) |
| Balance at December 31, 2016 | 9 | 398 | 6,885 | 4,086 | (13) | 11,356 |
| Net income after dividends on preferred and preference stock | — | — | — | 1,414 | — | 1,414 |
| Capital contributions from parent company | — | — | 443 | — | — | 443 |
| Other comprehensive income (loss) | — | — | — | — | 3 | 3 |
| Cash dividends on common stock | — | — | — | (1,281) | — | (1,281) |
| Other | — | — | — | (4) | — | (4) |
| Balance at December 31, 2017 | 9 | $ 398 | $ 7,328 | $ 4,215 | $ (10) | $ 11,931 |

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

NOTES TO FINANCIAL STATEMENTS
Georgia Power Company 2017 Annual Report

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1. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

General

Georgia Power Company (the Company) is a wholly-owned subsidiary of Southern Company, which is the parent company of the Company and three other traditional electric operating companies, as well as Southern Power, Southern Company Gas (as of July 1, 2016), SCS, Southern Linc, Southern Company Holdings, Inc. (Southern Holdings), Southern Nuclear, PowerSecure, Inc. (PowerSecure) (as of May 9, 2016), and other direct and indirect subsidiaries. The traditional electric operating companies – the Company, Alabama Power, Gulf Power, and Mississippi Power – are vertically integrated utilities providing electric service in four Southeastern states. The Company provides electric service to retail customers within its traditional service territory located within the State of Georgia and to wholesale customers in the Southeast. Southern Power 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 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, including the Company's Plant Hatch and Plant Vogtle Units 1 and 2, 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.

The equity method is used for subsidiaries in which the Company has significant influence but does not control.

The Company is subject to regulation by the FERC and the Georgia PSC. As such, the Company's financial statements reflect the effects of rate regulation in accordance with GAAP and comply with the accounting policies and practices prescribed by its regulatory commissions. The preparation of financial statements in conformity with GAAP requires the use of estimates, and the actual results may differ from those estimates. Certain prior years' data presented in the financial statements have been reclassified to conform to the current year presentation.

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

Recently Issued Accounting Standards

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 the Company's revenue, including energy provided to customers, is from tariff offerings that provide electricity without a defined contractual term, as well as longer-term contractual commitments, including PPAs.

The 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

energy-related derivatives, are excluded from the scope of ASC 606 and, therefore, will be accounted for and disclosed separately from revenues under ASC 606. The 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. The Company applied the modified retrospective method of adoption effective January 1, 2018. The 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

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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. ASU 2016-02 is effective for fiscal years beginning after December 15, 2018 and the Company will adopt the new standard effective January 1, 2019.

The 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, the 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 PPAs and cellular towers where the Company is the lessee and to outdoor lighting where the Company is the lessor. The Company is currently analyzing pole attachment agreements, and a lease determination has not been made at this time. While the Company has not yet determined the ultimate impact, adoption of ASU 2016-02 is expected to have a significant impact on the 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, the Company recognized any excess tax benefits and deficiencies related to the exercise and vesting of stock compensation as additional paid-in capital. In addition, the new guidance requires excess tax benefits for share-based payments to be included in net cash provided from operating activities rather than net cash provided from financing activities on the statement of cash flows. The Company elected to adopt the guidance in 2016 and reflect the related adjustments as of January 1, 2016. Prior year's data presented in the financial statements has not been adjusted. The Company also elected to recognize forfeitures as they occur. The new guidance did not have a material impact on the results of operations, financial position, or cash flows of the Company. See Notes 5 and 8 for disclosures impacted by ASU 2016-09.

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 the 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. The 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. The Company adopted ASU 2017-12 effective January 1, 2018 with no material impact on its financial statements.

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Affiliate Transactions

The Company has an agreement with SCS under which the following services are rendered to the Company at direct or allocated cost: general and design engineering, operations, purchasing, accounting, finance and treasury, tax, information technology, marketing, auditing, insurance and pension administration, human resources, systems and procedures, digital wireless communications, and other services with respect to business and operations, construction management, and power pool transactions. Costs for these services amounted to $625 million, $606 million, and $585 million in 2017, 2016, and 2015, respectively. Cost allocation methodologies used by SCS prior to the repeal of the Public Utility Holding Company Act of 1935, as amended, were approved by the SEC. Subsequently, additional cost allocation methodologies have been reported to the FERC and management believes they are reasonable. The FERC permits services to be rendered at cost by system service companies. See Note 7 under "Operating Leases" for information on leases of cellular tower space for the Company's digital wireless communications equipment.

The Company has an agreement with Southern Nuclear under which the following nuclear-related services are rendered to the Company at cost: general executive and advisory services; general operations, management, and technical services; administrative services including procurement, accounting, employee relations, systems, and procedures services; strategic planning and budgeting services; and other services with respect to business, operations, and construction management. Costs for these services amounted to $675 million, $666 million, and $681 million in 2017, 2016, and 2015, respectively. See Note 3 under "Retail Regulatory Matters – Nuclear Construction" for additional information.

The Company has entered into several PPAs with Southern Power for capacity and energy. Expenses associated with these PPAs were $235 million, $265 million, and $179 million in 2017, 2016, and 2015, respectively. See Note 6 under "Capital Leases" and Note 7 under "Fuel and Purchased Power Agreements" for additional information.

The Company has a joint ownership agreement with Gulf Power under which Gulf Power owns a 25% portion of Plant Scherer Unit 3. Under this agreement, the Company operates Plant Scherer Unit 3 and Gulf Power reimburses the Company for its 25% proportionate share of the related non-fuel expenses, which were $11 million, $8 million, and $12 million in 2017, 2016, and 2015, respectively. See Note 4 for additional information.

In 2014, prior to Southern Company's acquisition of PowerSecure on May 9, 2016, the Company entered into agreements with PowerSecure to build solar power generation facilities at two U.S. Army bases, as approved by the Georgia PSC. In October 2016, the two facilities began commercial operation. Payments of $119 million made by the Company to PowerSecure under the agreements since 2014 are included in utility plant in service at December 31, 2017.

On September 1, 2016, Southern Company Gas acquired a 50% equity interest in Southern Natural Gas Company, L.L.C. (SNG). Prior to completion of the acquisition, SCS, as agent for the Company, had entered into a long-term interstate natural gas transportation agreement with SNG. The interstate transportation service provided to the Company by SNG pursuant to this agreement is governed by the terms and conditions of SNG's natural gas tariff and is subject to FERC regulation. Transportation costs under this agreement were $102 million in 2017 and $35 million for the period subsequent to Southern Company Gas' investment in SNG through December 31, 2016.

Prior to Southern Company's acquisition of Southern Company Gas, SCS, as agent for the Company, had agreements with certain subsidiaries of Southern Company Gas to purchase natural gas. Natural gas purchases made by the Company from Southern Company Gas' subsidiaries were $22 million in 2017 and $10 million for the period subsequent to Southern Company's acquisition of Southern Company Gas through December 31, 2016.

The Company provides incidental services to and receives such services from other Southern Company subsidiaries which are generally minor in duration and amount. Except as described herein, the Company neither provided nor received any material services to or from affiliates in 2017, 2016, or 2015.

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

See Note 7 under "Fuel and Purchased Power Agreements" for additional information.

Regulatory Assets and Liabilities

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

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

| | 2017 | 2016 | Note |
|---|---|---|---|
| | (in millions) | | |
| Retiree benefit plans | $1,313 | $1,348 | (a, k) |
| Asset retirement obligations | 945 | 893 | (b, k) |
| Deferred income tax charges | 521 | 681 | (b, c, k) |
| Storm damage reserves | 333 | 206 | (d) |
| Remaining net book value of retired assets | 146 | 166 | (e) |
| Loss on reacquired debt | 127 | 137 | (f, k) |
| Other regulatory assets | 119 | 97 | (g) |
| Vacation pay | 91 | 91 | (h, k) |
| Other cost of removal obligations | 40 | 3 | (b) |
| Cancelled construction projects | 36 | 44 | (i) |
| Deferred income tax credits | (3,248 ) | (121 ) | (b, c) |
| Other regulatory liabilities | (191 ) | (39 ) | (j, k) |
| Total regulatory assets (liabilities), net | $232 | $3,506 | |

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

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

(b) Asset retirement and other cost of removal obligations and deferred income tax assets are recovered and deferred income tax liabilities are amortized over the related property lives, which may range up to 65 years. Asset retirement and removal liabilities will be settled and trued up following completion of the related activities. Included in the deferred income tax assets is $21 million for the retiree Medicare drug subsidy, which is recovered and amortized, as approved by the Georgia PSC, through 2022.

(c) As a result of Tax Reform Legislation, these balances include $145 million of deferred income tax assets related to CWIP for Plant Vogtle Units 3 and 4 and $626 million of deferred income tax liabilities, neither of which are subject to normalization. The recovery and amortization of these amounts will be determined by the Georgia PSC. See Note 3 under "Retail Regulatory Matters – Rate Plans" and Note 5 for additional information.

(d) 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 "Retail Regulatory Matters – Storm Damage Recovery" for additional information.

(e) Amortized as approved by the Georgia PSC over periods not exceeding 10 years or through 2024. The net book value of Plant Mitchell Unit 3 at December 31, 2017 was $10 million, which will continue to be amortized through December 31, 2019 as provided in the 2013 ARP. Amortization of the remaining net book value of Plant Mitchell Unit 3 at December 31, 2019, which is expected to be approximately $4 million, and $31 million related to obsolete inventories of certain retired units is expected to be determined by the Georgia PSC in the 2019 base rate case. See Note 3 under "Retail Regulatory Matters – Integrated Resource Plan" for additional information.

(f) Recovered over either the remaining life of the original issue or, if refinanced, over the remaining life of the new issue, which currently does not exceed 35 years.

(g) Comprised of several components including deferred nuclear outages, environmental remediation, building lease, demand-side management tariff under-recovery, and fuel-hedging losses. Deferred nuclear outages are recorded and recovered or amortized over the outage cycles of each nuclear unit, which does not exceed 24 months. The building lease is recorded and recovered or amortized as approved by the Georgia PSC through 2020. The amortization of environmental remediation and demand-side management tariff under-recovery of $54 million at December 31, 2017 is expected to be determined by the Georgia PSC in the 2019 base rate case. Fuel-hedging losses are recovered through the Company's fuel cost recovery mechanism upon final settlement.

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

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

(j) Comprised of certain customer refunds and fuel-hedging gains. As ordered by the Georgia PSC on January 11, 2018, approximately $188 million of the proceeds pursuant to the Toshiba Guarantee will be refunded to customers in 2018. Fuel-hedging gains are refunded through the Company's fuel cost recovery mechanism upon final settlement. See Note 3 under "Nuclear Construction" for additional information on the customer refunds related to the Toshiba Guarantee.

(k) Generally not earning a return as they are excluded from rate base or are offset in rate base by a corresponding asset or liability.

In the event that a portion of the Company's operations is no longer subject to applicable accounting rules for rate regulation, the Company would be required to write off to income or reclassify to accumulated OCI related regulatory assets and liabilities that are not specifically recoverable through regulated rates. In addition, the Company would be required to determine if any impairment to other assets, including plant, exists and write down the assets, if impaired, to their fair values. All regulatory assets and liabilities are to be reflected in rates. See Note 3 under "Retail Regulatory Matters" for additional information.

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Revenues

Wholesale capacity revenues from PPAs are recognized either on a levelized basis over the appropriate contract period or the amount billable under the contract terms. Energy and other revenues are recognized as services are provided. Unbilled revenues related to retail sales are accrued at the end of each fiscal period. Electric rates for the Company include provisions to adjust billings for fluctuations in fuel costs, the energy component of purchased power costs, and certain other costs. Revenues are adjusted for differences between the actual recoverable costs and amounts billed in current regulated rates.

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

Fuel Costs

Fuel costs are expensed as the fuel is used. Fuel expense generally includes fuel transportation costs and the cost of purchased emissions allowances as they are used. Fuel expense also includes the amortization of the cost of nuclear fuel.

Income and Other Taxes

The Company uses the liability method of accounting for deferred income taxes and provides deferred income taxes for all significant income tax temporary differences. Taxes that are collected from customers on behalf of governmental agencies to be remitted to these agencies are presented net on the statements of income.

Federal ITCs utilized are deferred and, upon utilization, amortized to income as a credit to reduce depreciation over the average life of the related property. The Company had $87 million in federal ITCs at December 31, 2017 that will expire by 2037. State ITCs are recognized in the period in which the credits are generated. The Company had state investment and other tax credit carryforwards totaling $495 million at December 31, 2017, which will expire between 2019 and 2028 and are expected to be fully utilized by 2026.

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

Property, Plant, and Equipment

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

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

| | 2017 | 2016 |
|---|---|---|
| | (in millions) | |
| Generation | $17,038 | $16,668 |
| Transmission | 5,947 | 5,779 |
| Distribution | 9,978 | 9,553 |
| General | 1,870 | 1,813 |
| Plant acquisition adjustment | 28 | 28 |
| Total plant in service | $34,861 | $33,841 |

The cost of replacements of property, exclusive of minor items of property, is capitalized. The cost of maintenance, repairs, and replacement of minor items of property is charged to other operations and maintenance expenses as incurred or performed with the exception of certain generating plant maintenance costs. As mandated by the Georgia PSC, the Company defers and amortizes nuclear refueling outage costs over the unit's operating cycle. The refueling cycles are 18 and 24 months for Plant Vogtle Units 1 and 2 and Plant Hatch Units 1 and 2, respectively.

Depreciation and Amortization

Depreciation of the original cost of utility plant in service is provided primarily by using composite straight-line rates, which approximated 2.7% in 2017, 2.8% in 2016, and 2.7% in 2015. Depreciation studies are conducted periodically to update the composite rates that are approved by the Georgia PSC and the FERC. When property subject to depreciation is retired or otherwise disposed of in the normal course of business, its original cost, together with the cost of removal, less salvage, is charged to accumulated depreciation. For other property dispositions, the applicable cost and accumulated depreciation are removed from

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the balance sheet accounts, and a gain or loss is recognized. Minor items of property included in the original cost of the plant are retired when the related property unit is retired.
Under the terms of the 2013 ARP, the Company amortized approximately $14 million annually from 2014 through 2016 of its remaining regulatory liability related to other cost of removal obligations.
Asset Retirement Obligations and Other Costs of Removal
AROs are computed as the present value of the estimated ultimate costs for an asset's future retirement and are recorded in the period in which the liability is incurred. The costs are capitalized as part of the related long-lived asset and depreciated over the asset's useful life. In the absence of quoted market prices, AROs are estimated using present value techniques in which estimates of future cash outlays associated with the asset retirements are discounted using a credit-adjusted risk-free rate. Estimates of the timing and amounts of future cash outlays are based on projections of when and how the assets will be retired and the cost of future removal activities. The Company has received accounting guidance from the Georgia PSC allowing the continued accrual and recovery of other retirement costs for long-lived assets that the Company does not have a legal obligation to retire. Accordingly, amounts to be recovered are reflected in the balance sheets as a regulatory asset and any accumulated removal costs for future obligations are reflected in the balance sheets as a regulatory liability.
The ARO liability primarily relates to the Company's ash ponds, landfills, and gypsum cells that are subject to the Disposal of Coal Combustion Residuals from Electric Utilities final rule published by the EPA in 2015 (CCR Rule). In addition, the Company has retirement obligations related to decommissioning of the Company's nuclear facilities, which include the Company's ownership interests in Plant Hatch and Plant Vogtle Units 1 and 2, underground storage tanks, and asbestos removal. The Company also has identified retirement obligations related to certain transmission and distribution facilities, including the disposal of polychlorinated biphenyls in certain transformers; leasehold improvements; equipment on customer property; and property associated with the Company's rail lines and natural gas pipelines. However, liabilities for the removal of these assets have not been recorded because the settlement timing for the retirement obligations related to these assets is indeterminable and, therefore, the fair value of the retirement obligations cannot be reasonably estimated. A liability for these AROs will be recognized when sufficient information becomes available to support a reasonable estimation of the ARO. The Company will continue to recognize in the statements of income allowed removal costs in accordance with its regulatory treatment. Any differences between costs recognized in accordance with accounting standards related to asset retirement and environmental obligations and those reflected in rates are recognized as either a regulatory asset or liability in the balance sheets as ordered by the Georgia PSC. See "Nuclear Decommissioning" herein for additional information on amounts included in rates.
Details of the AROs included in the balance sheets are as follows:

| | 2017 | 2016 |
|---|---|---|
| | (in millions) | |
| Balance at beginning of year | $2,532 | $1,916 |
| Liabilities incurred | 4 | — |
| Liabilities settled | (120 ) | (123 ) |
| Accretion | 89 | 77 |
| Cash flow revisions | 133 | 662 |
| Balance at end of year | $2,638 | $2,532 |

In 2017 and 2016, the increases in cash flow revisions are primarily related to changes to the Company's 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 Company 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. The Company has external trust funds (Funds) to comply with the NRC's regulations. Use of the Funds is restricted to nuclear decommissioning activities. The Funds are managed and invested in accordance with applicable requirements of various regulatory bodies, including the NRC, the FERC, and the Georgia PSC, as well as the IRS. While the Company is allowed to prescribe an overall investment policy to the Funds' managers, the Company and its affiliates are not

allowed to engage in the day-to-day management of the Funds or to mandate individual investment decisions.
Day-to-day management of the investments in the Funds is delegated to unrelated third party managers with oversight by the management of the Company. The Funds' managers are authorized, within certain investment guidelines, to actively buy and sell securities at their own discretion in order to maximize the return on the Funds' investments. The Funds are invested in a tax-efficient manner in a diversified mix of equity and fixed income securities and are reported as trading securities.
The Company records the investment securities held in the Funds at fair value, as disclosed in Note 10, as management believes that fair value best represents the nature of the Funds. Gains and losses, whether realized or unrealized, are recorded in the regulatory liability for AROs in the balance sheets and are not included in net income or OCI. Fair value adjustments and realized gains and losses are determined on a specific identification basis.
The Funds participate in a securities lending program through the managers of the Funds. Under this program, the Funds' investment securities are loaned to institutional investors for a fee. Securities loaned are fully collateralized by cash, letters of credit, and/or securities issued or guaranteed by the U.S. government or its agencies or instrumentalities. As of December 31, 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 $929 million, consisting of equity securities of $415 million, debt securities of $502 million, and $12 million of other securities. At December 31, 2016, investment securities in the Funds totaled $814 million, consisting of equity securities of $326 million, debt securities of $477 million, and $11 million of other securities. 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 $568 million, $803 million, and $980 million 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 $108 million, which included $83 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 $38 million, which included $14 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 $3 million, which included $26 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.
The NRC's minimum external funding requirements are based on a generic estimate of the cost to decommission only the radioactive portions of a nuclear unit based on the size and type of reactor. The Company has filed plans with the NRC designed to ensure that, over time, the deposits and earnings of the Funds will provide the minimum funding amounts prescribed by the NRC.

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Site study cost is the estimate to decommission a specific facility as of the site study year. The decommissioning cost estimates are based on prompt dismantlement and removal of the plant from service. The actual decommissioning costs may vary from these estimates because of changes in the assumed date of decommissioning, changes in NRC requirements, or changes in the assumptions used in making these estimates. The estimated costs of decommissioning are based on the most current study performed in 2015. The site study costs and external trust funds for decommissioning as of December 31, 2017 based on the Company's ownership interests were as follows:

| | Plant Hatch | Plant Vogtle Units 1 and 2 |
|---|---|---|
| Decommissioning periods: | | |
| Beginning year | 2034 | 2047 |
| Completion year | 2075 | 2079 |
| | (in millions) | |
| Site study costs: | | |
| Radiated structures | $678 | $ 568 |
| Spent fuel management | 160 | 147 |
| Non-radiated structures | 64 | 89 |
| Total site study costs | $902 | $ 804 |
| External trust funds | $583 | $ 346 |

For ratemaking purposes, the Company's decommissioning costs are based on the NRC generic estimate to decommission the radioactive portion of the facilities and the site study estimate for spent fuel management as of 2012. Under the 2013 ARP, the Georgia PSC approved annual decommissioning cost for ratemaking of $4 million and $2 million for Plant Hatch and Plant Vogtle Units 1 and 2, respectively. Significant assumptions used to determine the costs for ratemaking include an estimated inflation rate of 2.4% and an estimated trust earnings rate of 4.4%. The Company expects the Georgia PSC to review and adjust, if necessary, the amounts collected in rates for nuclear decommissioning costs in the Company's 2019 base rate case.

Allowance for Funds Used During Construction

The Company records AFUDC, which represents the estimated debt and equity costs of capital funds that are necessary to finance the construction of new regulated facilities. While cash is not realized currently, AFUDC increases the revenue requirement and is recovered over the service life of the plant through a higher rate base and higher depreciation. The equity component of AFUDC is not included in calculating taxable income. For the years 2017, 2016, and 2015, the average AFUDC rates were 5.6%, 6.9%, and 6.5%, respectively, and AFUDC capitalized was $63 million, $68 million, and $56 million, respectively. AFUDC, net of income taxes, as a percentage of net income after dividends on preferred and preference stock was 3.8%, 4.6%, and 3.9% for 2017, 2016, and 2015, respectively. See Note 3 under "Retail Regulatory Matters – Nuclear Construction" for additional information on the inclusion of construction costs related to Plant Vogtle Units 3 and 4 in rate base effective January 1, 2011.

Impairment of Long-Lived Assets and Intangibles

The Company evaluates long-lived assets for impairment when events or changes in circumstances indicate that the carrying value of such assets may not be recoverable. The determination of whether an impairment has occurred is based on either a specific regulatory disallowance or an estimate of undiscounted future cash flows attributable to the assets, as compared with the carrying value of the assets. If an impairment has occurred, the amount of the impairment recognized is determined by either the amount of regulatory disallowance or by estimating the fair value of the assets and recording a loss if the carrying value is greater than the fair value. For assets identified as held for sale, the carrying value is compared to the estimated fair value less the cost to sell in order to determine if an impairment loss is required. Until the assets are disposed of, their estimated fair value is re-evaluated when circumstances or events change.

Storm Damage Recovery

The Company defers and recovers certain costs related to damages from major storms as mandated by the Georgia PSC. Beginning January 1, 2014, the Company is accruing $30 million annually under the 2013 ARP that is recoverable through base rates. As of December 31, 2017 and December 31, 2016, the balance in the 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. The annual recovery amount is expected to be reviewed by the Georgia PSC and adjusted in future regulatory proceedings. As a result of this regulatory treatment, costs related to storms are generally not expected to have a material impact on the Company's earnings. See Note 3 under "Retail Regulatory Matters – Storm Damage Recovery" for additional information.

Environmental Remediation Recovery

The Company maintains a reserve for environmental remediation as mandated by the Georgia PSC. In 2013, the Georgia PSC approved the 2013 ARP including the recovery of approximately $2 million annually through the environmental compliance cost recovery (ECCR) tariff. The Company recognizes a liability for environmental remediation costs only when it determines a loss is probable and reasonably estimable and reduces the reserve as expenditures are incurred. Any difference between the liabilities accrued and cost recovered through rates is deferred as a regulatory asset or liability. The annual recovery amount is expected to be reviewed by the Georgia PSC and adjusted in future regulatory proceedings. As a result of this regulatory treatment, environmental remediation liabilities generally are not expected to have a material impact on the Company's earnings. As of December 31, 2017, the balance of the environmental remediation liability was $22 million and is included in other current liabilities. As of December 31, 2017, the balance of under recovered environmental remediation costs was $49 million, with approximately $2 million included in other regulatory assets, current and approximately $47 million included as other regulatory assets, deferred. As of December 31, 2016, the balance of the environmental remediation liability was $17 million and is included in other current liabilities. As of December 31, 2016, the balance of under recovered environmental remediation costs was $35 million, with approximately $2 million included in other regulatory assets, current and approximately $33 million included as other regulatory assets, deferred. See Note 3 under "Environmental Matters – Environmental Remediation" for additional information.

Cash and Cash Equivalents

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

Materials and Supplies

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

Fuel Inventory

Fuel inventory includes the average cost of coal, natural gas, and oil, as well as transportation and emissions allowances. Fuel is recorded to inventory when purchased and then expensed, at weighted average cost, as used and recovered by the Company through fuel cost recovery rates approved by the Georgia PSC. Emissions allowances granted by the EPA are included in inventory at zero cost.

Financial Instruments

The Company uses derivative financial instruments to limit exposure to fluctuations in interest rates, the prices of certain fuel purchases, and electricity purchases and sales. All derivative financial instruments are recognized as either assets or liabilities on the balance sheets (included in "Other") and are measured at fair value. See Note 10 for additional information regarding fair value. Substantially all of the Company's bulk energy purchases and sales contracts that meet the definition of a derivative are excluded from fair value accounting requirements because they qualify for the "normal" scope exception, and are accounted for under the accrual method. Derivative contracts that qualify as cash flow hedges of anticipated transactions or are recoverable through the Georgia PSC-approved fuel-hedging program result in the deferral of related gains and losses in OCI or regulatory assets and liabilities, respectively, until the hedged transactions occur. Any ineffectiveness arising from cash flow hedges is recognized currently in net income. Other derivative contracts that qualify as fair value hedges are marked to market through current period income and are recorded on a net basis in the statements of income. Cash flows from derivatives are classified on the statements of cash flows in the same category as the hedged item. See Note 11 for additional information regarding derivatives.

The Company offsets fair value amounts recognized for multiple derivative instruments executed with the same counterparty under netting arrangements. Additionally, the Company had no outstanding collateral repayment obligations or rights to reclaim collateral arising from derivative instruments recognized at December 31, 2017.
The 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.

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

2. RETIREMENT BENEFITS
The Company has a defined benefit, trusteed, pension plan covering substantially all employees. This qualified pension plan is funded in accordance with requirements of the Employee Retirement Income Security Act of 1974, as amended (ERISA). No contributions to the qualified pension plan were made for the year ended December 31, 2017 and no mandatory contributions to the qualified pension plan are anticipated for the year ending December 31, 2018. The Company also provides certain defined benefit pension plans for a selected group of management and highly compensated employees. Benefits under these non-qualified pension plans are funded on a cash basis. In addition, the Company provides certain medical care and life insurance benefits for retired employees through other postretirement benefit plans. The Company funds its other postretirement trusts to the extent required by the Georgia PSC and the FERC. For the year ending December 31, 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% | 4.65% | 4.18% |
| Discount rate – interest costs | 3.72 | 3.86 | 4.18 |
| Discount rate – service costs | 4.83 | 5.03 | 4.49 |
| Expected long-term return on plan assets | 7.95 | 8.20 | 8.20 |
| Annual salary increase | 4.46 | 4.46 | 3.59 |
| Other postretirement benefit plans | | | |
| Discount rate – benefit obligations | 4.23% | 4.49% | 4.03% |
| Discount rate – interest costs | 3.55 | 3.67 | 4.03 |
| Discount rate – service costs | 4.63 | 4.88 | 4.39 |
| Expected long-term return on plan assets | 6.79 | 6.27 | 6.48 |
| Annual salary increase | 4.46 | 4.46 | 3.59 |

| Assumptions used to determine benefit obligations: | 2017 | 2016 |
|---|---|---|
| Pension plans | | |
| Discount rate | 3.79% | 4.40% |
| Annual salary increase | 4.46 | 4.46 |
| Other postretirement benefit plans | | |
| Discount rate | 3.68% | 4.23% |
| Annual salary increase | 4.46 | 4.46 |

The Company estimates the expected rate of return on pension plan and other postretirement benefit plan assets using a financial model to project the expected return on each current investment portfolio. The analysis projects an expected rate of return on each of 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.

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

| | 1 Percent Increase | 1 Percent Decrease |
|---|---|---|
| | (in millions) | |
| Benefit obligation | $59 | $ 50 |
| Service and interest costs | 2 | 2 |

Pension Plans

The total accumulated benefit obligation for the pension plans was $3.8 billion at December 31, 2017 and $3.5 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:

| | 2017 | 2016 |
|---|---|---|
| | (in millions) | |
| Change in benefit obligation | | |
| Benefit obligation at beginning of year | $3,800 | $3,615 |
| Service cost | 74 | 70 |
| Interest cost | 138 | 136 |
| Benefits paid | (187 ) | (164 ) |
| Actuarial (gain) loss | 363 | 143 |
| Balance at end of year | 4,188 | 3,800 |
| Change in plan assets | | |
| Fair value of plan assets at beginning of year | 3,621 | 3,196 |
| Actual return (loss) on plan assets | 610 | 288 |
| Employer contributions | 14 | 301 |
| Benefits paid | (187 ) | (164 ) |
| Fair value of plan assets at end of year | 4,058 | 3,621 |
| Accrued liability | $(130 ) | $(179 ) |

At December 31, 2017, the projected benefit obligations for the qualified and non-qualified pension plans were $4.0 billion and $153 million, respectively. All pension plan assets are related to the qualified pension plan.

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

| | 2017 | 2016 |
|---|---|---|
| | (in millions) | |
| Prepaid pension costs | $23 | $ — |
| Other regulatory assets, deferred | 1,105 | 1,129 |
| Other current liabilities | (15) | (14) |
| Employee benefit obligations | (138) | (165) |

Presented below are the amounts included in 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.

| | 2017 | 2016 | Estimated Amortization in 2018 |
|---|---|---|---|
| | (in millions) | | |
| Prior service cost | $14 | $17 | $ 2 |
| Net (gain) loss | 1,091 | 1,112 | 69 |
| Regulatory assets | $1,105 | $1,129 | |

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:

| | 2017 | 2016 |
|---|---|---|
| | (in millions) | |
| Regulatory assets: | | |
| Beginning balance | $1,129 | $1,076 |
| Net (gain) loss | 36 | 99 |
| Change in prior service costs | — | 14 |
| Reclassification adjustments: | | |
| Amortization of prior service costs | (3) | (5) |
| Amortization of net gain (loss) | (57) | (55) |
| Total reclassification adjustments | (60) | (60) |
| Total change | (24) | 53 |
| Ending balance | $1,105 | $1,129 |

Components of net periodic pension cost were as follows:

| | 2017 | 2016 | 2015 |
|---|---|---|---|
| | (in millions) | | |
| Service cost | $74 | $70 | $73 |
| Interest cost | 138 | 136 | 154 |
| Expected return on plan assets | (283) | (258) | (251) |
| Recognized net (gain) loss | 57 | 55 | 76 |
| Net amortization | 3 | 5 | 9 |
| Net periodic pension cost | $(11) | $8 | $61 |

Net periodic pension cost is the sum of service cost, interest cost, and other costs netted against the expected return on plan assets. The expected return on plan assets is determined by multiplying the expected rate of return on plan assets and the market-related value of plan assets. In determining the market-related value of plan assets, the Company has elected to amortize changes in the

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market value of all plan assets over five years rather than recognize the changes immediately. As a result, the accounting value of plan assets that is used to calculate the expected return on plan assets differs from the current fair value of the plan assets.

Future benefit payments reflect expected future service and are estimated based on assumptions used to measure the projected benefit obligation for the pension plans. At December 31, 2017, estimated benefit payments were as follows:

| | Benefit Payments (in millions) |
|---|---|
| 2018 | $ 196 |
| 2019 | 201 |
| 2020 | 207 |
| 2021 | 210 |
| 2022 | 216 |
| 2023 to 2027 | 1,156 |

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:

| | 2017 | 2016 |
|---|---|---|
| | (in millions) | |
| Change in benefit obligation | | |
| Benefit obligation at beginning of year | $847 | $854 |
| Service cost | 7 | 6 |
| Interest cost | 29 | 30 |
| Benefits paid | (51 ) | (45 ) |
| Actuarial (gain) loss | 28 | (1 ) |
| Retiree drug subsidy | 3 | 3 |
| Balance at end of year | 863 | 847 |
| Change in plan assets | | |
| Fair value of plan assets at beginning of year | 354 | 358 |
| Actual return (loss) on plan assets | 54 | 21 |
| Employer contributions | 26 | 17 |
| Benefits paid | (48 ) | (42 ) |
| Fair value of plan assets at end of year | 386 | 354 |
| Accrued liability | $(477) | $(493) |

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:

| | 2017 | 2016 |
|---|---|---|
| | (in millions) | |
| Other regulatory assets, deferred | $202 | $213 |
| Employee benefit obligations | (477 ) | (493 ) |

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Presented below are the amounts included in regulatory assets 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.

| | 2017 | 2016 | Estimated Amortization in 2018 |
|---|---|---|---|
| | (in millions) | | |
| Prior service cost | $5 | $6 | $ 1 |
| Net (gain) loss | 197 | 207 | 9 |
| Regulatory assets | $202 | $213 | |

The changes in the balance of regulatory assets related to the other postretirement benefit plans for the plan years ended December 31, 2017 and 2016 are presented in the following table:

| | 2017 | 2016 |
|---|---|---|
| | (in millions) | |
| Regulatory assets: | | |
| Beginning balance | $213 | $223 |
| Net (gain) loss | (2 ) | — |
| Reclassification adjustments: | | |
| Amortization of prior service costs | (1 ) | (1 ) |
| Amortization of net gain (loss) | (8 ) | (9 ) |
| Total reclassification adjustments | (9 ) | (10 ) |
| Total change | (11 ) | (10 ) |
| Ending balance | $202 | $213 |

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

| | 2017 | 2016 | 2015 |
|---|---|---|---|
| | (in millions) | | |
| Service cost | $7 | $6 | $7 |
| Interest cost | 29 | 30 | 34 |
| Expected return on plan assets | (25 ) | (22 ) | (24 ) |
| Net amortization | 9 | 10 | 11 |
| Net periodic postretirement benefit cost | $20 | $24 | $28 |

Future benefit payments, including prescription drug benefits, reflect expected future service and are estimated based on assumptions used to measure the APBO for the other postretirement benefit plans. Estimated benefit payments are reduced by drug subsidy receipts expected as a result of the Medicare Prescription Drug, Improvement, and Modernization Act of 2003 as follows:

| | Benefit Payments | Subsidy Receipts | Total |
|---|---|---|---|
| | (in millions) | | |
| 2018 | $55 | $ (3 ) | $ 52 |
| 2019 | 55 | (3 ) | 52 |
| 2020 | 56 | (3 ) | 53 |
| 2021 | 57 | (4 ) | 53 |
| 2022 | 58 | (4 ) | 54 |
| 2023 to 2027 | 288 | (21 ) | 267 |

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Benefit Plan Assets
Pension plan and other postretirement benefit plan assets are managed and invested in accordance with all applicable requirements, including ERISA and the Internal Revenue Code of 1986, as amended. The Company's investment policies for both the pension plan and the other postretirement benefit plans cover a diversified mix of assets, including equity and fixed income securities, real estate, and private equity. Derivative instruments are used primarily to gain efficient exposure to the various asset classes and as hedging tools. The Company minimizes the risk of large losses primarily through diversification but also monitors and manages other aspects of risk.
The composition of the Company's pension plan and other postretirement benefit plan assets as of December 31, 2017 and 2016, along with the targeted mix of assets for each plan, is presented below:

| | Target | 2017 | 2016 |
|---|---|---|---|
| Pension plan assets: | | | |
| Domestic equity | 26 % | 31 % | 29 % |
| International equity | 25 | 25 | 22 |
| Fixed income | 23 | 24 | 29 |
| Special situations | 3 | 1 | 2 |
| Real estate investments | 14 | 13 | 13 |
| Private equity | 9 | 6 | 5 |
| Total | 100 % | 100% | 100% |
| Other postretirement benefit plan assets: | | | |
| Domestic equity | 36 % | 38 % | 35 % |
| International equity | 24 | 24 | 24 |
| Domestic fixed income | 33 | 31 | 35 |
| Special situations | 1 | 1 | 1 |
| Real estate investments | 4 | 4 | 4 |
| Private equity | 2 | 2 | 1 |
| Total | 100 % | 100% | 100% |

The investment strategy for plan assets related to the Company's qualified pension plan is to be broadly diversified across major asset classes. The asset allocation is established after consideration of various factors that affect the assets and liabilities of the pension plan including, but not limited to, historical and expected returns and interest rates, volatility, correlations of asset classes, the current level of assets and liabilities, and the assumed growth in assets and liabilities. Because a significant portion of the liability of the pension plan is long-term in nature, the assets are invested consistent with long-term investment expectations for return and risk. To manage the actual asset class exposures relative to the target asset allocation, the Company employs a formal rebalancing program. As additional risk management, external investment managers and service providers are subject to written guidelines to ensure appropriate and prudent investment practices. Management believes the portfolio is well-diversified with no significant concentrations of risk.
Investment Strategies
Detailed below is a description of the investment strategies for each major asset category for the pension and other postretirement benefit plans disclosed above:

- Domestic equity. A mix of large and small capitalization stocks with generally an equal distribution of value and growth attributes, managed both actively and through passive index approaches.
- International equity. A mix of growth stocks and value stocks with both developed and emerging market exposure, managed both actively and through passive index approaches.
- Fixed income. A mix of domestic and international bonds.
- Trust-owned life insurance (TOLI). Investments of the Company's taxable trusts aimed at minimizing the impact of taxes on the portfolio.

- Special situations. Investments in opportunistic strategies with the objective of diversifying and enhancing returns and exploiting short-term inefficiencies as well as investments in promising new strategies of a longer-term nature.

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- Real estate investments. Investments in traditional private market, equity-oriented investments in real properties (indirectly through pooled funds or partnerships) and in publicly traded real estate securities.
- Private equity. Investments in private partnerships that invest in private or public securities typically through privately-negotiated and/or structured transactions, including leveraged buyouts, venture capital, and distressed debt.

Benefit Plan Asset Fair Values

Following are the fair value measurements for the pension plan and the other postretirement benefit plan assets as of December 31, 2017 and 2016. The fair values presented are prepared in accordance with GAAP. For purposes of determining the fair value of the pension plan and other postretirement benefit plan assets and the appropriate level designation, management relies on information provided by the plan's trustee. This information is reviewed and evaluated by management with changes made to the trustee information as appropriate.

Valuation methods of the primary fair value measurements disclosed in the following tables are as follows:

- Domestic and international equity. Investments in equity securities such as common stocks, American depositary receipts, and real estate investment trusts that trade on a public exchange are classified as Level 1 investments and are valued at the closing price in the active market. Equity investments with unpublished prices (i.e. pooled funds) are valued as Level 2, when the underlying holdings used to value the investment are comprised of Level 1 or Level 2 equity securities.
- Fixed income. Investments in fixed income securities are generally classified as Level 2 investments and are valued based on prices reported in the market place. Additionally, the value of fixed income securities takes into consideration certain items such as broker quotes, spreads, yield curves, interest rates, and discount rates that apply to the term of a specific instrument.
- TOLI. Investments in TOLI policies are classified as Level 2 investments and are valued based on the underlying investments held in the policy's separate account. The underlying assets are equity and fixed income pooled funds that are comprised of Level 1 and Level 2 securities.
- Real estate investments, private equity, and special situations investments. Investments in real estate, private equity, and special situations are generally classified as Net Asset Value as a Practical Expedient, since the underlying assets typically do not have publicly available observable inputs. The fund manager values the assets using various inputs and techniques depending on the nature of the underlying investments. Techniques may include purchase multiples for comparable transactions, comparable public company trading multiples, discounted cash flow analysis, prevailing market capitalization rates, recent sales of comparable investments, and independent third-party appraisals. The fair value of partnerships is determined by aggregating the value of the underlying assets less liabilities.

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The fair values of pension plan assets as of December 31, 2017 and 2016 are presented below. These fair value measurements exclude cash, receivables related to investment income, pending investments sales, and payables related to pending investment purchases.

| | Fair Value Measurements Using | | | | |
|---|---|---|---|---|---|
| | Quoted Prices in Active Markets for Identical Assets | Significant Other Observable Inputs | Significant Unobservable Inputs | Net Asset Value as a Practical Expedient | |
| As of December 31, 2017: | (Level 1) | (Level 2) | (Level 3) | (NAV) | Total |
| | (in millions) | | | | |
| Assets: | | | | | |
| Domestic equity(*) | $819 | $ 394 | $ — | $ — | $1,213 |
| International equity(*) | 529 | 477 | — | — | 1,006 |
| Fixed income: | | | | | |
| U.S. Treasury, government, and agency bonds | — | 286 | — | — | 286 |
| Mortgage- and asset-backed securities | — | 3 | — | — | 3 |
| Corporate bonds | — | 409 | — | — | 409 |
| Pooled funds | — | 221 | — | — | 221 |
| Cash equivalents and other | 74 | 4 | — | — | 78 |
| Real estate investments | 160 | — | — | 404 | 564 |
| Special situations | — | — | — | 61 | 61 |
| Private equity | — | — | — | 228 | 228 |
| Total | $1,582 | $ 1,794 | $ — | $ 693 | $4,069 |

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

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| As of December 31, 2016: | Fair Value Measurements Using Quoted Prices in Active Markets for Identical Assets (Level 1) | Significant Other Observable Inputs (Level 2) | Significant Unobservable Inputs (Level 3) | Net Asset Value as a Practical Expedient (NAV) | Total |
|---|---|---|---|---|---|
| | (in millions) | | | | |
| Assets: | | | | | |
| Domestic equity(*) | $686 | $ 317 | $ — | $ — | $1,003 |
| International equity(*) | 420 | 380 | — | — | 800 |
| Fixed income: | | | | | |
| U.S. Treasury, government, and agency bonds | — | 201 | — | — | 201 |
| Mortgage- and asset-backed securities | — | 4 | — | — | 4 |
| Corporate bonds | — | 338 | — | — | 338 |
| Pooled funds | — | 179 | — | — | 179 |
| Cash equivalents and other | 340 | 1 | — | — | 341 |
| Real estate investments | 106 | — | — | 394 | 500 |
| Special situations | — | — | — | 61 | 61 |
| Private equity | — | — | — | 188 | 188 |
| Total | $1,552 | $ 1,420 | $ — | $ 643 | $3,615 |

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

The fair values of 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 investments 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 |
|---|---|---|---|---|---|
| | (in millions) | | | | |
| Assets: | | | | | |
| Domestic equity(*) | $53 | $ 11 | $ — | $ — | $64 |
| International equity(*) | 14 | 46 | — | — | 60 |
| Fixed income: | | | | | |
| U.S. Treasury, government, and agency bonds | — | 6 | — | — | 6 |
| Corporate bonds | — | 11 | — | — | 11 |

| | | | | | |
|---|---|---|---|---|---|
| Pooled funds | — | 41 | — | — | 41 |
| Cash equivalents and other | 4 | — | — | — | 4 |
| Trust-owned life insurance | — | 173 | — | — | 173 |
| Real estate investments | 6 | — | — | 11 | 17 |
| Special situations | — | — | — | 2 | 2 |
| Private equity | — | — | — | 6 | 6 |
| Total | $77 | $ 288 | $ — | $ 19 | $384 |

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

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| | Fair Value Measurements Using | | | | |
|---|---|---|---|---|---|
| As of December 31, 2016: | Quoted Prices in Active Markets for Identical Assets (Level 1) | Significant Other Observable Inputs (Level 2) | Significant Unobservable Inputs (Level 3) | Net Asset Value as a Practical Expedient (NAV) | Total |
| | (in millions) | | | | |
| Assets: | | | | | |
| Domestic equity(*) | $45 | $ 9 | $ — | $ — | $54 |
| International equity(*) | 11 | 37 | — | — | 48 |
| Fixed income: | | | | | |
| U.S. Treasury, government, and agency bonds | — | 5 | — | — | 5 |
| Corporate bonds | — | 9 | — | — | 9 |
| Pooled funds | — | 38 | — | — | 38 |
| Cash equivalents and other | 15 | — | — | — | 15 |
| Trust-owned life insurance | — | 162 | — | — | 162 |
| Real estate investments | 3 | — | — | 11 | 14 |
| Special situations | — | — | — | 2 | 2 |
| Private equity | — | — | — | 5 | 5 |
| Total | $74 | $ 260 | $ — | $ 18 | $352 |

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

Employee Savings Plan

The Company also sponsors a 401(k) defined contribution plan covering substantially all employees. The Company matches a portion of the first 6% of employee base salary contributions. The maximum Company match is 5.1% of an employee's base salary. Total matching contributions made to the plan for 2017, 2016, and 2015 were $26 million, $27 million, and $26 million, respectively.

3. CONTINGENCIES AND REGULATORY MATTERS

General Litigation Matters

In 2011, plaintiffs filed a putative class action against the Company in the Superior Court of Fulton County, Georgia alleging that the Company's collection in rates of municipal franchise fees (all of which are remitted to municipalities) exceeded the amounts allowed in orders of the Georgia PSC and alleging certain state tort law claims. In November 2016, the Georgia Court of Appeals reversed the trial court's previous dismissal of the case and remanded the case to the trial court for further proceedings. The Company filed a petition for writ of certiorari with the Georgia Supreme Court, which was granted on August 28, 2017. A decision from the Georgia Supreme Court is expected in late 2018. The Company believes the plaintiffs' claims have no merit and intends to vigorously defend itself in this matter. The ultimate outcome of this matter cannot be determined at this time.

The Company is also subject to certain claims and legal actions arising in the ordinary course of business. In addition, the Company's business activities are subject to extensive governmental regulation related to public health and the environment, such as regulation of air emissions and water discharges. Litigation over environmental issues and claims of various types, including property damage, personal injury, common law nuisance, and citizen enforcement of environmental requirements such as 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 the Company cannot be predicted at this time; however, for current proceedings not specifically reported herein, management does not anticipate that the ultimate liabilities, if any, arising from such current proceedings would have a material effect on the Company's financial statements.

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Environmental Matters
Environmental Remediation
The Company must comply with environmental laws and regulations governing the handling and disposal of waste and releases of hazardous substances. Under these various laws and regulations, the Company may also incur substantial costs to clean up affected sites. See Note 1 under "Environmental Remediation Recovery" for additional information.
The Company recognizes a liability for environmental remediation costs only when it determines a loss is probable and reasonably estimable. The Company's environmental remediation liability as of December 31, 2017 and 2016 was $22 million and $17 million, respectively. The Company has been designated or identified as a potentially responsible party at sites governed by the Georgia Hazardous Site Response Act and/or by the federal Comprehensive Environmental Response, Compensation, and Liability Act, and assessment and potential cleanup of such sites is expected.
The ultimate outcome of these matters cannot be determined at this time; however, as a result of the Company's regulatory treatment for environmental remediation expenses described in Note 1 under "Environmental Remediation Recovery," these matters are not expected to have a material impact on the Company's financial statements.
Nuclear Fuel Disposal Costs
Acting through the DOE and pursuant to the Nuclear Waste Policy Act of 1982, the U.S. government entered into contracts with the Company that require the DOE to dispose of spent nuclear fuel and high level radioactive waste generated at Plant Hatch and Plant Vogtle Units 1 and 2 beginning no later than January 31, 1998. The DOE has yet to commence the performance of its contractual and statutory obligation to dispose of spent nuclear fuel. Consequently, the Company pursued and continues to pursue legal remedies against the U.S. government for its partial breach of contract.
In 2014, the Court of Federal Claims entered a judgment in favor of the Company in its spent nuclear fuel lawsuit seeking damages for the period from January 1, 2005 through December 31, 2010. In 2015, the Company 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.
In 2014, the Company filed lawsuits against the U.S. government for the costs of continuing to store spent nuclear fuel at Plant Hatch and Plant Vogtle Units 1 and 2 for the period from January 1, 2011 through December 31, 2013. The damage period was subsequently extended to December 31, 2014. On October 10, 2017, the Company 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 Plant 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, the Company expects to credit any recovery back for the benefit of customers in accordance with direction from the Georgia PSC and, therefore, no material impact on the Company's net income is expected.
On-site dry spent fuel storage facilities are operational at Plant Vogtle Units 1 and 2 and Plant Hatch. Facilities can be expanded to accommodate spent fuel through the expected life of each plant.
FERC Matters
The Company has authority from the FERC to sell electricity at market-based rates. Since 2008, that authority, for certain balancing authority areas, has been conditioned on compliance with the requirements of an energy auction, which the FERC found to be tailored mitigation that addresses potential market power concerns. In accordance with FERC regulations governing such authority, the traditional electric operating companies (including the Company) and Southern Power filed a triennial market power analysis in 2014, which included continued reliance on the energy auction as tailored mitigation. In 2015, the FERC issued an order finding that the traditional electric operating companies' (including the Company's) and Southern Power's existing tailored mitigation may not effectively mitigate

the potential to exert market power in certain areas served by the traditional electric operating companies and in some adjacent areas. The FERC directed the traditional electric operating companies (including the Company) and Southern Power to show why market-based rate authority should not be revoked in these areas or to provide a mitigation plan to further address market power concerns. The traditional electric operating companies (including the Company) and Southern Power filed a request for rehearing and filed their response with the FERC in 2015.

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

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the traditional electric operating companies' (including the Company's) and Southern Power's potential to exert market power in certain areas served by the traditional electric operating companies (including the Company) and in some adjacent areas. On May 17, 2017, the FERC accepted the traditional electric operating companies' (including the Company's) 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' (including the Company's) and Southern Power's June 29, 2017 triennial updated market power analysis. The FERC directed the traditional electric operating companies (including the Company) 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 (including the Company) 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.

Retail Regulatory Matters

Rate Plans

Pursuant to the terms and conditions of a settlement agreement related to Southern Company's acquisition of Southern Company Gas approved by the Georgia PSC in April 2016, the 2013 ARP will continue in effect until December 31, 2019, and the Company will be required to file its next base rate case by July 1, 2019. Furthermore, through December 31, 2019, the Company and Atlanta Gas Light Company each will retain their respective merger savings, net of transition costs, as defined in the settlement agreement; through December 31, 2022, such net merger savings applicable to each will be shared on a 60/40 basis with their respective customers; thereafter, all merger savings will be retained by customers.

In accordance with the 2013 ARP, the Georgia PSC approved increases to tariffs effective January 1, 2016 as follows: (1) traditional base tariff rates by approximately $49 million; (2) ECCR 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, the Company's retail ROE is set at 10.95% and earnings are evaluated against a retail ROE range of 10.00% to 12.00%. Two-thirds of any earnings above 12.00% will be directly refunded to customers, with the remaining one-third retained by the Company. There will be no recovery of any earnings shortfall below 10.00% on an actual basis. In 2015, the Company's retail ROE was within the allowed retail ROE range. In 2016, the Company's retail ROE exceeded 12.00%, and the Company will refund to retail customers approximately $44 million in 2018, as approved by the Georgia PSC on January 16, 2018. In 2017, the Company'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, the Company is required to submit its analysis of the Tax Reform Legislation and related recommendations to address the related impacts on the Company'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 the Company'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 the Company sold its 33% ownership interest in the Intercession City unit to Duke Energy Florida, LLC.

Additionally, the Georgia PSC approved the Company's environmental compliance strategy and related expenditures proposed in the 2016 IRP, including measures taken to comply with existing government-imposed environmental mandates, subject to limits on expenditures for Plant McIntosh Unit 1 and Plant Hammond Units 1 through 4.
The Georgia PSC approved the reclassification of the remaining net book value of Plant Mitchell Unit 3 and costs associated with materials and supplies remaining at the unit retirement date to a regulatory asset. Recovery of the unit's net book value will continue through December 31, 2019, as provided in the 2013 ARP. The timing of the recovery of the remaining balance of the unit's net book value as of December 31, 2019 and costs associated with materials and supplies remaining at the unit retirement date was deferred for consideration in the Company's 2019 base rate case.

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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 the Company was approved, as well as consideration for no more than 200 MWs of capacity as part of a renewable commercial and industrial program.

In 2017, the Company 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. The Company 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 the Company'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 rate case.

Fuel Cost Recovery

The Company has established fuel cost recovery rates approved by the Georgia PSC. In 2015, the Georgia PSC approved the Company's request to lower annual billings by approximately $350 million effective January 1, 2016. In May 2016, the Georgia PSC approved the Company'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 the Company's cumulative over or under recovered fuel balance no later than September 1, 2018 and evaluate the need to file a fuel case unless the Company deems it necessary to file a fuel case at an earlier time. The Company 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.

The Company's fuel cost recovery mechanism includes costs associated with a natural gas hedging program, as revised and approved by the Georgia PSC, allowing the use of an array of derivative instruments within a 48-month time horizon.

The Company's under recovered fuel balance totaled $165 million at December 31, 2017 and is included in current assets. At December 31, 2016, the Company's over recovered fuel balance totaled $84 million and is included in over recovered fuel clause revenues, 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 the Company's revenues or net income, but will affect cash flow.

Storm Damage Recovery

The Company 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 the Company's transmission and distribution facilities during September 2017 and October 2016, respectively. The incremental restoration costs related to these hurricanes deferred in the regulatory asset for storm damage totaled approximately $260 million. At December 31, 2017, the total balance in the regulatory asset related to storm damage was $333 million. The rate of storm damage cost recovery is expected to be adjusted as part of the Company'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 the Company's financial statements. See Note 1 under "Storm Damage Recovery" for additional information regarding the Company's storm damage reserve.

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, the Company, 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, the Company 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 the Company's recommendation to continue construction.

The Company expects Plant Vogtle Units 3 and 4 to be placed in service by November 2021 and November 2022, respectively. The Company'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). The Company'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. The Company 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, the Company, 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. The Company, 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, the Company 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 the Company'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, the Company, 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 the Company, the other Vogtle Owners, and certain affiliates of MEAG Power against Westinghouse, and the Company and the other Vogtle Owners surrendered the Westinghouse Letters of Credit.

Additionally, on June 9, 2017, the Company, 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, the Company, 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

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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 the Company and the DOE, the Company 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 the Company determines that any of the Company'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 the Company or Southern Nuclear for any action or inaction in connection with their performance as agent for the Vogtle Owners is limited to removal of the Company 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 the Company to recover financing costs for nuclear construction projects certified by the Georgia PSC. Financing costs are recovered on all applicable certified costs through annual adjustments to the NCCR tariff up to the certified capital cost of $4.418 billion. As of December 31, 2017, the Company had recovered approximately $1.6 billion of financing costs. On January 30, 2018, the Company 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.

The Company 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 the Company 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 the Company.

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 the Company 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) the Company 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 the Company's revised schedule placing Plant Vogtle Units 3 and 4 in service in November 2021 and November 2022, respectively;

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(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 the Company'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 the Company'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 the Company'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 the Company's seventeenth VCM report are based do not materialize, both the Company 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. The Company believes the appeal has no merit; however, an adverse outcome in this appeal could have a material impact on the 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 the Company'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. The Company 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. The Company'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

The Company'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.

The Company 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

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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, the Company 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 the Company, 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 the Company 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.

4. JOINT OWNERSHIP AGREEMENTS

The Company and Alabama Power own equally all of the outstanding capital stock of SEGCO, which owns electric generating units with a total rated capacity of 1,020 MWs, as well as associated transmission facilities. SEGCO uses natural gas as the primary fuel source for 1,000 MWs of its generating capacity. The capacity of these units is sold equally to the Company and Alabama Power under a power contract. The Company and Alabama Power make payments sufficient to provide for the operating expenses, taxes, interest expense, and an ROE. The Company's share of purchased power totaled $78 million in 2017, $57 million in 2016, and $78 million in 2015 and is included in purchased power, affiliates in the statements of income. The Company accounts for SEGCO using the equity method. See Note 7 under "Guarantees" for additional information.

The Company owns undivided interests in Plants Vogtle, Hatch, Wansley, and Scherer in varying amounts jointly with one or more of the following entities: 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, Jacksonville Electric Authority, and Gulf Power. Under these agreements, the Company has been contracted to operate and maintain the plants as agent for the co-owners and is jointly and severally liable for third party claims related to these plants. In addition, the Company jointly owns the Rocky Mountain pumped storage hydroelectric plant with OPC, which is the operator of the plant. In August 2016, the Company sold its 33% ownership interest in the Intercession City combustion turbine unit to Duke Energy Florida, LLC.

At December 31, 2017, the Company's percentage ownership and investment (exclusive of nuclear fuel) in jointly-owned facilities in commercial operation with the above entities were as follows:

| Facility (Type) | Company Ownership | | Plant in Service | Accumulated Depreciation | CWIP |
|---|---|---|---|---|---|
| | | | (in millions) | | |
| Plant Vogtle (nuclear) | | | | | |
| Units 1 and 2 | 45.7 | % | $3,564 | $ 2,141 | $ 70 |
| Plant Hatch (nuclear) | 50.1 | | 1,321 | 595 | 87 |
| Plant Wansley (coal) | 53.5 | | 1,053 | 335 | 72 |

| | | | | |
|---|---|---|---|---|
| Plant Scherer (coal) | | | | |
| Units 1 and 2 | 8.4 | 261 | 93 | 8 |
| Unit 3 | 75.0 | 1,232 | 468 | 26 |
| Rocky Mountain (pumped storage) | 25.4 | 182 | 132 | — |

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

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The Company 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 "Retail Regulatory Matters – Nuclear Construction" for additional information.

## 5. INCOME TAXES

On behalf of the Company, Southern Company files a consolidated federal income tax return and various combined and separate state income tax returns. Under a joint consolidated income tax allocation agreement, each Southern Company subsidiary's current and deferred tax expense is computed on a stand-alone basis and no subsidiary is allocated more current expense than would be paid if it filed a separate income tax return. In accordance with IRS regulations, each company is jointly and severally liable for the federal tax liability.

### Federal Tax Reform Legislation

Following the enactment of 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, the Company considers all amounts recorded in the financial statements as a result of Tax Reform Legislation to be "provisional" as discussed in SAB 118 and subject to revision. The Company is awaiting additional guidance from industry and income tax authorities in order to finalize its accounting. The ultimate impact of 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 "Retail Regulatory Matters – Rate Plans" for additional information.

### Current and Deferred Income Taxes

Details of income tax provisions are as follows:

| | 2017 | 2016 | 2015 |
|---|---|---|---|
| | (in millions) | | |
| Federal – | | | |
| Current | $256 | $391 | $515 |
| Deferred | 504 | 319 | 176 |
| | 760 | 710 | 691 |
| State – | | | |
| Current | 116 | 6 | 81 |
| Deferred | (46) | 64 | (3) |
| | 70 | 70 | 78 |
| Total | $830 | $780 | $769 |

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The tax effects of temporary differences between the carrying amounts of assets and liabilities in the financial statements and their respective tax bases, which give rise to deferred tax assets and liabilities, are as follows:

| | 2017 | 2016 |
|---|---|---|
| | (in millions) | |
| Deferred tax liabilities – | | |
| Accelerated depreciation | $3,540 | $5,266 |
| Property basis differences | — | 957 |
| Employee benefit obligations | 287 | 428 |
| Premium on reacquired debt | 34 | 56 |
| Regulatory assets – | | |
| Storm damage reserves | 89 | 83 |
| Employee benefit obligations | 348 | 546 |
| Asset retirement obligations | 501 | 726 |
| Retired assets | 30 | 55 |
| Asset retirement obligations | 132 | 182 |
| Other | 100 | 83 |
| Total | 5,061 | 8,382 |
| Deferred tax assets – | | |
| Federal effect of state deferred taxes | 72 | 173 |
| Employee benefit obligations | 423 | 661 |
| Property basis differences | 92 | 105 |
| Other deferred costs | 69 | 100 |
| State investment tax credit carryforward | 318 | 201 |
| Federal tax credit carryforward | 97 | 84 |
| Unbilled fuel revenue | 26 | 47 |
| Regulatory liabilities associated with asset retirement obligations | 5 | 33 |
| Asset retirement obligations | 631 | 908 |
| Regulatory liability associated with Tax Reform Legislation (not subject to normalization) | 123 | — |
| Other | 30 | 70 |
| Total | 1,886 | 2,382 |
| Accumulated deferred income taxes | $3,175 | $6,000 |

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

At December 31, 2017, tax-related regulatory assets to be recovered from customers were $521 million. These assets are primarily attributable to tax benefits flowed through to customers in prior years and deferred taxes previously recognized at rates lower than the current enacted tax law.

At December 31, 2017, tax-related regulatory liabilities to be credited to customers were $3.2 billion. These liabilities are primarily attributable to deferred taxes previously recognized at rates higher than the current enacted tax law.

In accordance with regulatory requirements, federal ITCs are deferred and, upon utilization, amortized over the average life of the related property with such amortization normally applied as a credit to reduce depreciation in the statements of income. Credits amortized in this manner amounted to $10 million in each of 2017, 2016, and 2015.

State investment tax credits are recognized in the period in which the credits are generated and totaled $50 million in 2017, $42 million in 2016, and $33 million in 2015. At December 31, 2017, the Company had $87 million in federal ITC carryforwards that will expire by 2037 and $318 million in state ITC carryforwards that will expire between 2020 and 2028.

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Effective Tax Rate

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

| | 2017 | 2016 | 2015 |
|---|---|---|---|
| Federal statutory rate | 35.0 % | 35.0 % | 35.0 % |
| State income tax, net of federal deduction | 2.0 | 2.1 | 2.5 |
| Non-deductible book depreciation | 0.7 | 0.8 | 1.2 |
| AFUDC equity | (0.6 ) | (0.8 ) | (0.7 ) |
| Tax Reform Legislation | (0.4 ) | — | — |
| Other | — | (0.4 ) | (0.4 ) |
| Effective income tax rate | 36.7 % | 36.7 % | 37.6 % |

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 the Company's overall effective tax rate. See Note 1 under "Recently Issued Accounting Standards" for additional information.

Unrecognized Tax Benefits

The Company had no material unrecognized tax benefits as of December 31, 2017 and no material changes in unrecognized tax benefits for any year presented.

The Company classifies interest on tax uncertainties as interest expense; however, the Company did not have any accrued interest or penalties for unrecognized tax benefits for any year presented.

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

The IRS has finalized its audits of Southern Company's consolidated federal income tax returns through 2016. Southern Company is a participant in the Compliance Assurance Process of the IRS. The audits for the Company's state income tax returns have either been concluded, or the statute of limitations has expired, for years prior to 2011.

6. FINANCING

Securities Due Within One Year

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

| | 2017 | 2016 |
|---|---|---|
| | (in millions) | |
| Senior notes | $750 | $450 |
| Capital leases | 11 | 10 |
| Other long-term debt | 100 | — |
| Unamortized debt issuance expense | (1 ) | — |
| Total | $860 | $460 |

Maturities through 2022 applicable to total long-term debt are as follows: $861 million in 2018; $513 million in 2019; $1.0 billion in 2020; $375 million in 2021; and $518 million in 2022.

Bank Term Loans

In June 2017, the Company entered into three floating rate bank loans in aggregate principal amounts of $50 million, $150 million, and $100 million, with maturity dates of December 1, 2017, May 31, 2018, and June 28, 2018, respectively, bearing interest based on one-month LIBOR. Also in June 2017, the Company borrowed $500 million pursuant to an uncommitted bank credit arrangement, which bears interest at a rate agreed upon by the Company and the bank from time to time and is payable on no less than 30 days' demand by the bank. The proceeds from these bank loans were used to repay a portion of the Company's

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existing indebtedness and for working capital and other general corporate purposes, including the Company's continuous construction program.
In August 2017, the Company repaid $250 million of the $500 million aggregate principal amount outstanding pursuant to its uncommitted bank credit arrangement. Also in August 2017, the Company amended its $100 million floating rate bank loan to extend the maturity date from June 28, 2018 to October 26, 2018. In December 2017, the Company repaid the remaining $250 million aggregate principal amount outstanding pursuant to its uncommitted bank credit arrangement.
At December 31, 2017, the Company had a total of $250 million in bank term loans outstanding. Subsequent to December 31, 2017, the Company repaid its outstanding $150 million and $100 million floating rate bank loans due May 31, 2018 and October 26, 2018, respectively. At December 31, 2016, the Company had no bank term loans outstanding.
The outstanding bank loans as of December 31, 2017 had covenants that limited debt levels to 65% of total capitalization, as defined in the agreements. For purposes of these definitions, debt excludes certain hybrid securities. At December 31, 2017, the Company was in compliance with its debt limits.
Senior Notes
In March 2017, the Company issued $450 million aggregate principal amount of Series 2017A 2.00% Senior Notes due March 30, 2020 and $400 million aggregate principal amount of Series 2017B 3.25% Senior Notes due March 30, 2027. The proceeds were used to repay a portion of the Company's short-term indebtedness and for general corporate purposes, including the Company's continuous construction program.
In August 2017, the Company issued $500 million aggregate principal amount of Series 2017C 2.00% Senior Notes due September 8, 2020. The proceeds were used to repay the Company's $50 million floating rate bank loan due December 1, 2017 and outstanding commercial paper borrowings and for general corporate purposes.
At December 31, 2017 and 2016, the Company had $7.1 billion and $6.2 billion of senior notes outstanding, respectively, which included senior notes due within one year. These senior notes are effectively subordinated to all secured debt of the Company, which aggregated $2.8 billion at both December 31, 2017 and 2016. As of December 31, 2017, the Company's secured debt included borrowings of $2.6 billion guaranteed by the DOE and capital lease obligations of $154 million. As of December 31, 2016, the Company's secured debt included borrowings of $2.6 billion guaranteed by the DOE and capital lease obligations of $169 million. See Note 7 and "DOE Loan Guarantee Borrowings" herein for additional information.
Pollution Control Revenue Bonds
Pollution control revenue bond obligations represent loans to the Company from public authorities of funds derived from sales by such authorities of revenue bonds issued to finance pollution control and solid waste disposal facilities. The Company is required to make payments sufficient for the authorities to meet principal and interest requirements of such bonds. The amount of tax-exempt pollution control revenue bond obligations outstanding at both December 31, 2017 and 2016 was $1.8 billion.
In April 2017, the Company purchased and held $27 million aggregate principal amount of Development Authority of Burke County (Georgia) Pollution Control Revenue Bonds (Georgia Power Company Plant Vogtle Project), Fifth Series 1995. In October 2017, the Company remarketed these bonds to the public.
In August 2017, the Company purchased and held $38 million aggregate principal amount of Development Authority of Bartow County (Georgia) Pollution Control Revenue Bonds (Georgia Power Company Plant Bowen Project), First Series 1997. In October 2017, the Company remarketed these bonds to the public.
Junior Subordinated Notes
At December 31, 2017, the Company had a total of $270 million of junior subordinated notes outstanding. At December 31, 2016, the Company had no junior subordinated notes outstanding.
In September 2017, the Company 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 the Company's

preferred and preference stock. See "Outstanding Classes of Capital Stock" herein for additional information.

DOE Loan Guarantee Borrowings

Pursuant to the loan guarantee program established under Title XVII of the Energy Policy Act of 2005 (Title XVII Loan Guarantee Program), the Company and the DOE entered into the Loan Guarantee Agreement in 2014, under which the DOE agreed to guarantee the obligations of the Company under a note purchase agreement (FFB Note Purchase Agreement) among the DOE, the Company, and the FFB and a related promissory note (FFB Promissory Note). The FFB Note Purchase Agreement and

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the FFB Promissory Note provide for a multi-advance term loan facility (FFB Credit Facility), under which the Company may make term loan borrowings through the FFB.
On July 27, 2017, the Company entered into an amendment to the Loan Guarantee Agreement (LGA Amendment) in connection with the DOE's consent to the Company'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, the Company 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) the Company'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 the Company 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 the Company 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 the Company, and the Company is obligated to reimburse the DOE for any payments the DOE is required to make to the FFB under the guarantee. The Company's reimbursement obligations to the DOE are full recourse and secured by a first priority lien on (i) the Company's 45.7% undivided ownership interest in Plant Vogtle Units 3 and 4 (primarily the units under construction, the related real property, and any nuclear fuel loaded in the reactor core) and (ii) the Company's rights and obligations under the principal contracts relating to Plant Vogtle Units 3 and 4. There are no restrictions on the Company's ability to grant liens on other property.
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, the Company had $2.6 billion of borrowings outstanding under the FFB Credit Facility.
Under the Loan Guarantee Agreement, the Company is subject to customary borrower affirmative and negative covenants and events of default. In addition, the Company is subject to project-related reporting requirements and other project-specific covenants and events of default.
In the event certain mandatory prepayment events occur, the FFB's commitment to make further advances under the FFB Credit Facility will terminate and the Company will be required to prepay the outstanding principal amount of all borrowings under the FFB Credit Facility over a period of five years (with level principal amortization). Among other things, these mandatory prepayment events include (i) the termination of the Vogtle Services Agreement or rejection

of the Vogtle Services Agreement in bankruptcy if the Company does not maintain access to intellectual property rights under the IP Licenses; (ii) a decision by the Company 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 the Company 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 the Company's ability to repay the outstanding borrowings under the FFB Credit Facility. Under certain circumstances, insurance proceeds and any proceeds from an event of taking must be applied to immediately prepay outstanding borrowings under the FFB Credit Facility. In addition, if the Company discontinues construction of Plant Vogtle Units 3 and 4, the Company 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 the Company under the Guarantee Settlement Agreement. The Company 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 the Company's rights and obligations under the principal agreements relating to Plant Vogtle Units 3 and 4 and to acquire all or a portion of the Company's ownership interest in Plant Vogtle Units 3 and 4.

Capital Leases

Assets acquired under capital leases are recorded in the balance sheets as utility plant in service, and the related obligations are classified as long-term debt. At December 31, 2017 and 2016, the Company had a capital lease asset for its corporate headquarters building of $61 million, with accumulated depreciation at December 31, 2017 and 2016 of $39 million and $33 million, respectively. At December 31, 2017 and 2016, the capitalized lease obligation was $22 million and $28 million, respectively, with an annual interest rate of 7.9%. For ratemaking purposes, the Georgia PSC has allowed the lease payments in cost of service with no return on the capital lease asset. The difference between the depreciation and the lease payments allowed for ratemaking purposes is recovered as operating expenses as ordered by the Georgia PSC. The annual operating expense incurred for this capital lease was not material for any year presented.

At December 31, 2017 and 2016, the Company had capital lease assets related to two PPAs with Southern Power of $144 million and $149 million, respectively, with accumulated amortization at December 31, 2017 and 2016 of $29 million and $19 million, respectively. At December 31, 2017 and 2016, the related capitalized lease obligations were $132 million and $141 million, respectively. The annual interest rates range from 10% to 12% for these two capital lease PPAs. For ratemaking purposes, the Georgia PSC has included the capital lease asset amortization in cost of service and the interest in the Company's cost of debt. See Note 1 under "Affiliate Transactions" and Note 7 under "Fuel and Purchased Power Agreements" for additional information.

Assets Subject to Lien

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

Outstanding Classes of Capital Stock

The Company currently has preferred stock, Class A preferred stock, preference stock, and common stock authorized. The Company has shares of its common stock outstanding. In October 2017, the Company redeemed all 1.8 million shares ($45 million aggregate liquidation amount) of its 6.125% Series Class A Preferred Stock and 2.25 million shares ($225 million aggregate liquidation amount) of its 6.50% Series 2007A Preference Stock. No shares of preferred stock, Class A preferred stock, or preference stock were outstanding at December 31, 2017.

Dividend Restrictions

The Company can only pay dividends to Southern Company out of retained earnings or paid-in-capital.

Bank Credit Arrangements

At December 31, 2017, the Company had a $1.75 billion committed credit arrangement with banks, of which $1.73 billion was unused. In May 2017, the Company amended its multi-year credit arrangement which, among other things, extended the maturity date from 2020 to 2022.
This bank credit arrangement requires payment of commitment fees based on the unused portion of the commitments. Commitment fees average less than 1/4 of 1% for the Company.
This bank credit arrangement contains a covenant that limits the Company's debt levels to 65% of total capitalization, as defined in the agreement. For purposes of this definition, debt excludes certain hybrid securities. At December 31, 2017, the Company was in compliance with the debt limit covenant.

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

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A portion of the $1.73 billion unused credit with banks is allocated to provide liquidity support to the Company's pollution control revenue bonds and commercial paper program. The amount of variable rate pollution control revenue bonds outstanding requiring liquidity support as of December 31, 2017 was $550 million as compared to $868 million at December 31, 2016. In addition, at December 31, 2017, the Company had $469 million of pollution control revenue bonds outstanding that were required to be remarketed within the next 12 months.

The Company makes short-term borrowings primarily through a commercial paper program that has the liquidity support of the Company's committed bank credit arrangement described above. Commercial paper is included in notes payable in the balance sheets.

Details of short-term borrowings outstanding were as follows:

| | Short-term Debt at the End of the Period | | |
|---|---|---|---|
| | Amount Outstanding | Weighted Average Interest Rate | |
| | (in millions) | | |
| December 31, 2017: | | | |
| Short-term bank debt | $ 150 | 2.2 | % |
| December 31, 2016: | | | |
| Commercial paper | $ 392 | 1.1 | % |

7. COMMITMENTS

Fuel and Purchased Power Agreements

To supply a portion of the fuel requirements of its generating plants, the Company has entered into various long-term commitments for the procurement and delivery of fossil and nuclear fuel which are not recognized on the balance sheets. In 2017, 2016, and 2015, the Company incurred fuel expense of $1.7 billion, $1.8 billion, and $2.0 billion, respectively, the majority of which was purchased under long-term commitments. The Company expects that a substantial amount of its future fuel needs will continue to be purchased under long-term commitments.

The Company has commitments regarding a portion of a 5% interest in the original cost of Plant Vogtle Units 1 and 2 owned by MEAG Power that are in effect until the latter of the retirement of the plant or the latest stated maturity date of MEAG Power's bonds issued to finance such ownership interest. The payments for capacity are required whether or not any capacity is available. The energy cost is a function of each unit's variable operating costs. Portions of the capacity payments relate to costs in excess of MEAG Power's Plant Vogtle Units 1 and 2 allowed investment for ratemaking purposes. The present value of these portions at the time of the disallowance was written off. Generally, the cost of such capacity and energy is included in purchased power, non-affiliates in the statements of income. Capacity payments totaled $9 million, $11 million, and $10 million in 2017, 2016, and 2015, respectively.

The Company has also entered into various long-term PPAs, some of which are accounted for as capital or operating leases. Total capacity expense under PPAs accounted for as operating leases was $199 million, $217 million, and $203 million for 2017, 2016, and 2015, respectively. Contingent rent expense under energy-only solar PPAs of $73 million, $39 million, and $8 million for 2017, 2016, and 2015, respectively, was recognized as services were performed. Estimated total long-term obligations at December 31, 2017 were as follows:

| | Affiliate Capital Leases | Affiliate Operating Leases | Non-Affiliate Operating Leases | Vogtle Units 1 and 2 Capacity Payments | Total |
|---|---|---|---|---|---|
| | (in millions) | | | | |
| 2018 | $23 | $ 62 | $ 127 | $ 7 | $219 |
| 2019 | 23 | 63 | 128 | 6 | 220 |
| 2020 | 23 | 65 | 124 | 4 | 216 |
| 2021 | 24 | 66 | 125 | 5 | 220 |
| 2022 | 24 | 67 | 126 | 4 | 221 |
| 2023 and thereafter | 182 | 412 | 773 | 38 | 1,405 |
| Total | $299 | $ 735 | $ 1,403 | $ 64 | $2,501 |
| Less: amounts representing executory costs[(a)] | 45 | | | | |
| Net minimum lease payments | 254 | | | | |
| Less: amounts representing interest[(b)] | 120 | | | | |
| Present value of net minimum lease payments | $134 | | | | |

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

(b) Calculated using an adjusted incremental borrowing rate to reduce the present value of the net minimum lease payments to fair value.

SCS may enter into various types of wholesale energy and natural gas contracts acting as an agent for the Company and all of the other traditional electric operating companies and Southern Power. Under these agreements, each of the traditional electric operating companies and Southern Power may be jointly and severally liable. Accordingly, Southern Company has entered into keep-well agreements with the Company and each of the other traditional electric operating companies to ensure the Company will not subsidize or be responsible for any costs, losses, liabilities, or damages resulting from the inclusion of Southern Power as a contracting party under these agreements.

Operating Leases

The Company has entered into operating leases with Southern Linc and third parties for the use of cellular tower space. Substantially all of these agreements have initial terms ranging from five to 10 years and renewal options of up to 20 years. The Company has also entered into rental agreements for facilities, railcars, and other equipment with various terms and expiration dates. Total rent expense was $31 million, $28 million, and $29 million for 2017, 2016, and 2015, respectively. The Company includes any step rents, fixed escalations, and lease concessions in its computation of minimum lease payments.

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

| | Minimum Lease Payments | | |
|---|---|---|---|
| | Affiliate Operating Leases[a] | Non-Affiliate Operating Leases [b] | Total |
| | (in millions) | | |
| 2018 | $ 10 | $ 14 | $ 24 |
| 2019 | 11 | 11 | 22 |
| 2020 | 11 | 9 | 20 |
| 2021 | 9 | 8 | 17 |
| 2022 | 8 | 6 | 14 |
| 2023 and thereafter | 33 | 11 | 44 |
| Total | $ 82 | $ 59 | $ 141 |

(a) Includes operating leases for cellular tower space.
(b) Includes operating leases for cellular tower space, facilities, railcars, and other equipment.

Railcar minimum lease payments are disclosed at 100% of railcar lease obligations; however, a portion of these obligations is shared with the joint owners of Plants Scherer and Wansley. A majority of the rental expenses related to the railcar leases are recoverable through the fuel cost recovery clause as ordered by the Georgia PSC and the remaining portion is recovered through base rates.

In addition to the above rental commitments, the Company has obligations upon expiration of certain railcar leases with respect to the residual value of the leased property. These leases have terms expiring through 2024 with maximum obligations under these leases of $32 million. At the termination of the leases, the Company may either renew the lease, exercise its purchase option, or the property can be sold to a third party. The Company expects that the fair market value of the leased property would reduce the Company's payments under the residual value obligations.

Guarantees

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

In addition, in 2013, the Company entered into an agreement that requires the Company to guarantee certain payments of a gas supplier for Plant McIntosh for a period up to 15 years. The guarantee is expected to be terminated if certain events occur within one year of the initial gas deliveries in 2018. In the event the gas supplier defaults on payments, the maximum potential exposure under the guarantee is approximately $43 million.

As discussed earlier in this Note under "Operating Leases," the Company has entered into certain residual value guarantees related to railcar leases.

8. STOCK COMPENSATION

Stock-Based Compensation

Stock-based compensation primarily in the form of Southern Company performance share units and restricted stock units may be granted through the Omnibus Incentive Compensation Plan to a large segment of the Company's employees ranging from line management to executives. 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 895 current and former employees participating in the stock option, performance share unit, and restricted stock unit programs.

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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. The 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.
For the years ended December 31, 2017, 2016, and 2015, employees of the Company were granted performance share units of 138,102, 261,434, and 236,804, respectively. The weighted average grant-date fair value of TSR-based performance share units granted during 2017, 2016, and 2015, determined using a Monte Carlo simulation model to estimate the TSR of Southern Company's stock among the industry peers over the performance period, was $49.27, $45.17, and $46.41, respectively. The weighted average grant-date fair value of both EPS-based and ROE-based performance share units granted during 2017, 2016, and 2015 was $49.22, $48.84, and $47.78, respectively.
For the years ended December 31, 2017, 2016, and 2015, total compensation cost for performance share units recognized in income was $10 million, $15 million, and $15 million, respectively, with the related tax benefit also recognized in income of $4 million, $6 million, and $6 million, respectively. The compensation cost related to the grant of Southern Company performance share units to the Company's employees is recognized in the Company's financial statements with a corresponding credit to equity, representing a capital contribution from Southern Company. As of December 31, 2017, $3 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

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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.

For the year ended December 31, 2017, employees of the Company were granted 59,218 restricted stock units. The weighted average grant-date fair value of restricted stock units granted during 2017 was $49.22.

For the year ended December 31, 2017, total compensation cost for restricted stock units recognized in income was $3 million with the related tax benefit also recognized in income of $1 million. As of December 31, 2017, $1 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. Stock options expire no later than 10 years after the grant date and the latest possible exercise will occur no later than November 2024.

The compensation cost related to the grant of Southern Company stock options to the Company's employees is recognized in the Company's financial statements with a corresponding credit to equity, representing a capital contribution from Southern Company. Compensation cost and related tax benefits recognized in the Company's financial statements were not material for any year presented. As of December 31, 2017, all compensation cost related to stock option awards has been recognized.

The total intrinsic value of options exercised during the years ended December 31, 2017, 2016, and 2015 was $13 million, $18 million, and $9 million, respectively. No cash proceeds are received by the Company upon the exercise of stock options. The actual tax benefit realized by the Company for the tax deductions from stock option exercises totaled $5 million, $7 million, and $4 million for the years ended December 31, 2017, 2016, and 2015, respectively. Prior to the adoption of ASU 2016-09 in 2016, the excess tax benefits related to the exercise of stock options were recognized in the Company's financial statements with a credit to equity. Upon the adoption of ASU 2016-09, beginning in 2016, all tax benefits related to the exercise of stock options are recognized in income. As of December 31, 2017, the aggregate intrinsic value for the options outstanding and exercisable was $30 million.

9. NUCLEAR INSURANCE

Under the Price-Anderson Amendments Act (Act), the Company maintains agreements of indemnity with the NRC that, together with private insurance, cover third-party liability arising from any nuclear incident occurring at Plant Hatch and Plant Vogtle Units 1 and 2. The Act provides funds up to $13.4 billion for public liability claims that could arise from a single nuclear incident. Each nuclear plant is insured against this liability to a maximum of $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. The Company could be assessed up to $127 million per incident for each licensed reactor it operates but not more than an aggregate of $19 million per incident to be paid in a calendar year for each reactor. Such maximum assessment, excluding any applicable state premium taxes, for the Company, based on its ownership and buyback interests in all licensed reactors, is $247 million per incident, but not more than an aggregate of $37 million to be paid for each incident in any one year. Both the maximum assessment per reactor and the maximum yearly assessment are adjusted for inflation at least every five years. The next scheduled adjustment is due no later than September 10, 2018. See Note 4 for additional information on joint ownership agreements.

The Company is a member of Nuclear Electric Insurance Limited (NEIL), a mutual insurer established to provide property damage insurance in an amount up to $1.5 billion for members' operating nuclear generating facilities. Additionally, the Company has NEIL policies that currently provide decontamination, excess property insurance, and premature decommissioning coverage up to $1.25 billion for nuclear losses 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. The Company purchases limits based on the projected full cost of replacement power, subject to ownership limitations, and has elected a 12-week deductible waiting period for each facility.

A builders' risk property insurance policy has been purchased from NEIL for the construction of Plant Vogtle Units 3 and 4. This policy provides the Vogtle Owners up to $2.75 billion for accidental property damage occurring during construction.

Under each of the NEIL policies, members are subject to assessments each year if losses exceed the accumulated funds available to the insurer. The maximum annual assessments for the Company as of December 31, 2017 under the NEIL policies would be $81 million.

Claims resulting from terrorist acts are covered under both the ANI and NEIL policies (subject to normal policy limits). The aggregate, however, that NEIL will pay for all claims resulting from terrorist acts in any 12-month period is $3.2 billion plus such additional amounts NEIL can recover through reinsurance, indemnity, or other sources.

For all on-site property damage insurance policies for commercial nuclear power plants, the NRC requires that the proceeds of such policies shall be dedicated first for the sole purpose of placing the reactor in a safe and stable condition after an accident. Any remaining proceeds are to be applied next toward the costs of decontamination and debris removal operations ordered by the NRC, and any further remaining proceeds are to be paid either to the Company or to its debt trustees as may be appropriate under the policies and applicable trust indentures. In the event of a loss, the amount of insurance available might not be adequate to cover property damage and other expenses incurred. Uninsured losses and other expenses, to the extent not recovered from customers, would be borne by the Company and could have a material effect on the Company's financial condition and results of operations.

All retrospective assessments, whether generated for liability, property, or replacement power, may be subject to applicable state premium taxes.

## 10. FAIR VALUE MEASUREMENTS

Fair value measurements are based on inputs of observable and unobservable market data that a market participant would use in pricing the asset or liability. The use of observable inputs is maximized where available and the use of unobservable inputs is minimized for fair value measurement and reflects a three-tier fair value hierarchy that prioritizes inputs to valuation techniques used for fair value measurement.

- Level 1 consists of observable market data in an active market for identical assets or liabilities.
- Level 2 consists of observable market data, other than that included in Level 1, that is either directly or indirectly observable.
- Level 3 consists of unobservable market data. The input may reflect the assumptions of the Company of what a market participant would use in pricing an asset or liability. If there is little available market data, then the Company's own assumptions are the best available information.

In the case of multiple inputs being used in a fair value measurement, the lowest level input that is significant to the fair value measurement represents the level in the fair value hierarchy in which the fair value measurement is reported.

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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:

| 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) | Total |
|---|---|---|---|---|
| | (in millions) | | | |
| Assets: | | | | |
| Energy-related derivatives | $— | $ 6 | $ — | $6 |
| Nuclear decommissioning trusts:(*) | | | | |
| Domestic equity | 248 | 1 | — | 249 |
| Foreign equity | — | 166 | — | 166 |
| U.S. Treasury and government agency securities | — | 227 | — | 227 |
| Municipal bonds | — | 68 | — | 68 |
| Corporate bonds | — | 155 | — | 155 |
| Mortgage and asset backed securities | — | 40 | — | 40 |
| Other | 12 | 12 | — | 24 |
| Cash equivalents | 690 | — | — | 690 |
| Total | $950 | $ 675 | $ — | $1,625 |
| Liabilities: | | | | |
| Energy-related derivatives | $— | $ 19 | $ — | $19 |
| Interest rate derivatives | — | 5 | — | 5 |
| Total | $— | $ 24 | $ — | $24 |

(*) 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.

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As of December 31, 2016, assets and liabilities measured at fair value on a recurring basis during the period, together with their associated level of the fair value hierarchy, were as follows:

| | Fair Value Measurements Using | | | |
|---|---|---|---|---|
| As of December 31, 2016: | Quoted Prices in Active Markets for Identical Assets (Level 1) | Significant Other Observable Inputs (Level 2) | Significant Unobservable Inputs (Level 3) | Total |
| | (in millions) | | | |
| Assets: | | | | |
| Energy-related derivatives | $— | $ 44 | $ — | $44 |
| Interest rate derivatives | — | 2 | — | 2 |
| Nuclear decommissioning trusts:(*) | | | | |
| Domestic equity | 204 | 1 | — | 205 |
| Foreign equity | — | 121 | — | 121 |
| U.S. Treasury and government agency securities | — | 71 | — | 71 |
| Municipal bonds | — | 73 | — | 73 |
| Corporate bonds | — | 164 | — | 164 |
| Mortgage and asset backed securities | — | 164 | — | 164 |
| Other | 11 | 5 | — | 16 |
| Total | $215 | $ 645 | $ — | $860 |
| Liabilities: | | | | |
| Energy-related derivatives | $— | $ 8 | $ — | $8 |
| Interest rate derivatives | — | 3 | — | 3 |
| Total | $— | $ 11 | $ — | $11 |

(*) Includes the investment securities pledged to creditors and collateral received, and excludes receivables related to investment income, pending investment sales, 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 over-the-counter financial products for natural gas and physical power products, including, from time to time, basis swaps. These are standard products used within the energy industry and are valued using the market approach. The inputs used are mainly from observable market sources, such as forward natural gas prices, power prices, implied volatility, and overnight index swap interest rates. Interest rate derivatives are also standard over-the-counter products that are valued using observable market data and assumptions commonly used by market participants. The fair value of interest rate derivatives reflects the net present value of expected payments and receipts under the swap agreement based on the market's expectation of future interest rates. Additional inputs to the net present value calculation may include the contract terms, counterparty credit risk, and occasionally, implied volatility of interest rate options. The interest rate derivatives are categorized as Level 2 under Fair Value Measurements as these inputs are based on observable data and valuations of similar instruments. See Note 11 for additional information on how these derivatives are used.

The NRC requires licensees of commissioned nuclear power reactors to establish a plan for providing reasonable assurance of funds for future decommissioning. For fair value measurements of the investments within the nuclear decommissioning trusts, external pricing vendors are designated for each asset class with each security specifically assigned a primary pricing source. For investments held within commingled funds, fair value is determined at the end of each business day through the net asset value, which is established by obtaining the underlying securities' individual prices from the primary pricing source. A market price secured from the primary source vendor is then evaluated by management in its valuation of the assets within the trusts. As a general approach, fixed income market pricing vendors gather market data (including indices and market research reports) and integrate relative credit information, observed market movements, and sector news into proprietary pricing models, pricing 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.

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As of December 31, 2017 and 2016, other financial instruments for which the carrying amount did not equal fair value were as follows:

| | Carrying Amount | Fair Value |
|---|---|---|
| | (in millions) | |
| Long-term debt, including securities due within one year: | | |
| 2017 | $11,777 | $12,531 |
| 2016 | $10,516 | $11,034 |

The fair values are determined using Level 2 measurements and are based on quoted market prices for the same or similar issues or on current rates available to the Company.

11. DERIVATIVES

The Company is exposed to market risks, primarily commodity price risk and interest rate risk. To manage the volatility attributable to these exposures, the Company nets its exposures, where possible, to take advantage of natural offsets and enters into various derivative transactions for the remaining exposures pursuant to the Company's policies in areas such as counterparty exposure and risk management practices. The Company's policy is that derivatives are to be used primarily for hedging purposes and mandates strict adherence to all applicable risk management policies. Derivative positions are monitored using techniques including, but not limited to, market valuation, value at risk, stress testing, and sensitivity analysis. Derivative instruments are recognized at fair value in the balance sheets as either assets or liabilities and are presented on a net basis. See Note 10 for additional information. In the statements of cash flows, the cash impacts of settled energy-related and interest rate derivatives are recorded as operating activities.

Energy-Related Derivatives

The Company enters into energy-related derivatives to hedge exposures to electricity, gas, and other fuel price changes. However, due to cost-based rate regulations and other various cost recovery mechanisms, the Company has limited exposure to market volatility in energy-related commodity prices. The Company manages a fuel-hedging program through the use of financial derivative contracts, which is expected to continue to mitigate price volatility. At December 31, 2017 and 2016, substantially all of the Company's energy-related derivative contracts were designated as regulatory hedges and were related to the Company's fuel-hedging program. Effective January 1, 2016, the Georgia PSC approved changes to the Company's hedging program allowing it to use an array of derivative instruments within a 48-month time horizon.

Energy-related derivative contracts are accounted for under one of two methods:

- Regulatory Hedges – Energy-related derivative contracts which are designated as regulatory hedges relate primarily to the Company's fuel-hedging program, where gains and losses are initially recorded as regulatory liabilities and assets, respectively, and then are included in fuel expense as the underlying fuel is used in operations and ultimately recovered through the fuel cost recovery mechanism.
- Not Designated – Gains and losses on energy-related derivative contracts that are not designated or fail to qualify as hedges are recognized in the statements of income as incurred.

Some energy-related derivative contracts require physical delivery as opposed to financial settlement, and this type of derivative is both common and prevalent within the electric industry. When an energy-related derivative contract is settled physically, any cumulative unrealized gain or loss is reversed and the contract price is recognized in the respective line item representing the actual price of the underlying goods being delivered.

At December 31, 2017, the net volume of energy-related derivative contracts for natural gas positions totaled 163 million mmBtu, all of which expire by 2021, which is the longest hedge date.

In addition to the volume discussed above, the Company enters into physical natural gas supply contracts that provide the option to sell back excess gas due to operational constraints. The expected volume of natural gas subject to such a feature is 10 million mmBtu for the Company.

Interest Rate Derivatives

The Company may also enter into interest rate derivatives to hedge exposure to changes in interest rates. The derivatives employed as hedging instruments are structured to minimize ineffectiveness. Derivatives related to existing variable rate securities or forecasted transactions are accounted for as cash flow hedges where the effective portion of the derivatives' fair value gains or

losses is recorded in OCI and is reclassified into earnings at the same time the hedged transactions affect earnings, with any ineffectiveness recorded directly to earnings. At December 31, 2017, there were no cash flow hedges outstanding. Derivatives related to fixed rate securities are accounted for as fair value hedges, where the derivatives' fair value gains and losses and the hedged items' fair value gains and losses attributable to interest rate risk are both recorded directly to earnings, providing an offset, with any differences representing ineffectiveness.
At December 31, 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) |
| 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) |
| Total | $ 950 | | | | $ (4) |

The estimated pre-tax gains (losses) related to interest rate derivatives that will be reclassified from accumulated OCI to interest expense for the 12-month period ending December 31, 2018 total $(4) million. Deferred gains and losses related to interest rate derivative settlements of cash flow hedges are expected to be amortized into earnings through 2037.

Derivative Financial Statement Presentation and Amounts

The Company enters into energy-related and interest rate derivative contracts that may contain provisions that permit intra-contract netting of derivative receivables and payables for routine billing and offsets related to events of default and settlements. 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.

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At December 31, 2017 and 2016, the fair value of energy-related derivatives and interest rate derivatives was reflected in the balance sheets as follows:

| Derivative Category and Balance Sheet Location | 2017 Assets | 2017 Liabilities | 2016 Assets | 2016 Liabilities |
|---|---|---|---|---|
| | (in millions) | | | |
| Derivatives designated as hedging instruments for regulatory purposes | | | | |
| Energy-related derivatives: | | | | |
| Other current assets/Other current liabilities | $2 | $ (9) | $30 | $ 1 |
| Other deferred charges and assets/Other deferred credits and liabilities | 4 | (10) | 14 | 7 |
| Total derivatives designated as hedging instruments for regulatory purposes | $6 | $ (19) | $44 | $ 8 |
| Derivatives designated as hedging instruments in cash flow and fair value hedges | | | | |
| Interest rate derivatives: | | | | |
| Other current assets/Other current liabilities | $— | $ (4) | $2 | $ — |
| Other deferred charges and assets/Other deferred credits and liabilities | — | (1) | — | 3 |
| Total derivatives designated as hedging instruments in cash flow and fair value hedges | $— | $ (5) | $2 | $ 3 |
| Gross amounts recognized | $6 | $ (24) | $46 | $ 11 |
| Gross amounts offset | $(6) | $ 6 | $(8) | $ (8) |
| Net amounts recognized in the Balance Sheets | $— | $ (18) | $38 | $ 3 |

Energy-related derivatives not designated as hedging instruments were immaterial on the balance sheets for 2017 and 2016.

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:

| Derivative Category | Unrealized Losses Balance Sheet Location | 2017 | 2016 | Unrealized Gains Balance Sheet Location | 2017 | 2016 |
|---|---|---|---|---|---|---|
| | | (in millions) | | | (in millions) | |
| Energy-related derivatives: | Other regulatory assets, current | $(7) | $ — | Other regulatory liabilities, current | $ — | $ 29 |
| | Other regulatory assets, deferred | (6) | — | Other deferred credits and liabilities | — | 7 |
| Total energy-related derivative gains (losses) | | $(13) | $ — | | $ — | $ 36 |

For the years ended December 31, 2017, 2016, and 2015, the pre-tax effects of interest rate derivatives designated as cash flow hedging instruments on the statements of income were as follows:

| Derivatives in Cash Flow Hedging Relationships | Gain (Loss) Recognized in OCI on Derivative (Effective Portion) | | | Gain (Loss) Reclassified from Accumulated OCI into Income (Effective Portion) | | | |
|---|---|---|---|---|---|---|---|
| | | | | | Amount | | |
| Derivative Category | 2017 | 2016 | 2015 | Statements of Income Location | 2017 | 2016 | 2015 |
| | (in millions) | | | | (in millions) | | |
| Interest rate derivatives | $ 1 | $ — | $ (15) | Interest expense, net of amounts capitalized | $(4) | $(4) | $(3) |

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For the years ended December 31, 2017, 2016, and 2015, the pre-tax effects of interest rate derivatives designated as fair value hedging instruments on the statements of income were immaterial on a gross basis for the Company. Furthermore, the pre-tax effect of interest rate derivatives designated as fair value hedging instruments on the Company's statements of income were offset by changes to the carrying value of long-term debt. The gains and losses related to interest rate derivative settlements of fair value hedges are recorded directly to earnings.

There was no ineffectiveness recorded in earnings for any period presented. The pre-tax effect of energy-related derivatives not designated as hedging instruments on the statements of income was immaterial for all years presented.

Contingent Features

The Company does not have any credit arrangements that would require material changes in payment schedules or terminations as a result of a credit rating downgrade. There are certain derivatives that could require collateral, but not accelerated payment, in the event of various credit rating changes of certain affiliated companies. At December 31, 2017, the Company had no collateral posted with derivative counterparties to satisfy these arrangements.

At December 31, 2017, the fair value of derivative liabilities with contingent features was $2 million. However, because of joint and several liability features underlying these derivatives, the maximum potential collateral requirements arising from the credit-risk-related contingent features, at a rating below BBB- and/or Baa3, were $12 million, and include certain agreements that could require collateral in the event that one or more Southern Company system power pool participants has a credit rating change to below investment grade.

Generally, collateral may be provided by a Southern Company guaranty, letter of credit, or cash. If collateral is required, fair value amounts recognized for the right to reclaim cash collateral or the obligation to return cash collateral are not offset against fair value amounts recognized for derivatives executed with the same counterparty.

The Company is exposed to losses related to financial instruments in the event of counterparties' nonperformance. The Company only enters into agreements and material transactions with counterparties that have investment grade credit ratings by Moody's and S&P or with counterparties who have posted collateral to cover potential credit exposure. The Company has also established risk management policies and controls to determine and monitor the creditworthiness of counterparties in order to mitigate the Company's exposure to counterparty credit risk. Therefore, the Company does not anticipate a material adverse effect on the financial statements as a result of counterparty nonperformance.

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12. QUARTERLY FINANCIAL INFORMATION (UNAUDITED)
Summarized quarterly financial information for 2017 and 2016 is as follows:

| Quarter Ended | Operating Revenues | Operating Income | Net Income After Dividends on Preferred and Preference Stock |
|---|---|---|---|
| | (in millions) | | |
| March 2017 | $1,832 | $ 501 | $ 260 |
| June 2017 | 2,048 | 639 | 347 |
| September 2017 | 2,546 | 1,034 | 580 |
| December 2017 | 1,884 | 470 | 227 |
| | | | |
| March 2016 | $1,872 | $ 509 | $ 269 |
| June 2016 | 2,051 | 656 | 349 |
| September 2016 | 2,698 | 1,054 | 599 |
| December 2016 | 1,762 | 258 | 113 |

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

SELECTED FINANCIAL AND OPERATING DATA 2013-2017
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| | 2017 | 2016 | 2015 | 2014 | 2013 |
|---|---|---|---|---|---|
| Operating Revenues (in millions) | $ 8,310 | $ 8,383 | $ 8,326 | $ 8,988 | $ 8,274 |
| Net Income After Dividends on Preferred and Preference Stock (in millions) | $ 1,414 | $ 1,330 | $ 1,260 | $ 1,225 | $ 1,174 |
| Cash Dividends on Common Stock (in millions) | $ 1,281 | $ 1,305 | $ 1,034 | $ 954 | $ 907 |
| Return on Average Common Equity (percent) | 12.15 | 12.05 | 11.92 | 12.24 | 12.45 |
| Total Assets (in millions)[a][b] | $ 36,779 | $ 34,835 | $ 32,865 | $ 30,872 | $ 28,776 |
| Gross Property Additions (in millions) | $ 1,080 | $ 2,314 | $ 2,332 | $ 2,146 | $ 1,906 |
| Capitalization (in millions): | | | | | |
| Common stock equity | $ 11,931 | $ 11,356 | $ 10,719 | $ 10,421 | $ 9,591 |
| Preferred and preference stock | — | 266 | 266 | 266 | 266 |
| Long-term debt[a] | 11,073 | 10,225 | 9,616 | 8,563 | 8,571 |
| Total (excluding amounts due within one year) | $ 23,004 | $ 21,847 | $ 20,601 | $ 19,250 | $ 18,428 |
| Capitalization Ratios (percent): | | | | | |
| Common stock equity | 51.9 | 52.0 | 52.0 | 54.1 | 52.0 |
| Preferred and preference stock | — | 1.2 | 1.3 | 1.4 | 1.4 |
| Long-term debt[a] | 48.1 | 46.8 | 46.7 | 44.5 | 46.6 |
| Total (excluding amounts due within one year) | 100.0 | 100.0 | 100.0 | 100.0 | 100.0 |
| Customers (year-end): | | | | | |
| Residential | 2,185,782 | 2,155,945 | 2,127,658 | 2,102,673 | 2,080,358 |
| Commercial[c] | 308,939 | 305,488 | 302,891 | 300,186 | 297,493 |
| Industrial[c] | 10,644 | 10,537 | 10,429 | 10,192 | 10,063 |
| Other | 9,766 | 9,585 | 9,261 | 9,003 | 8,623 |
| Total | 2,515,131 | 2,481,555 | 2,450,239 | 2,422,054 | 2,396,537 |
| Employees (year-end) | 6,986 | 7,527 | 7,989 | 7,909 | 7,886 |

(a) A reclassification of debt issuance costs from Total Assets to Long-term debt of $124 million and $62 million is reflected for years 2014 and 2013, respectively, in accordance with new accounting standards adopted in 2015 and applied retrospectively.

(b) A reclassification of deferred tax assets from Total Assets of $34 million and $68 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 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.

SELECTED FINANCIAL AND OPERATING DATA 2013-2017 (continued)
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| | 2017 | 2016 | 2015 | 2014 | 2013 |
|---|---|---|---|---|---|
| Operating Revenues (in millions): | | | | | |
| Residential | $3,236 | $3,318 | $3,240 | $3,350 | $3,058 |
| Commercial | 3,092 | 3,077 | 3,094 | 3,271 | 3,077 |
| Industrial | 1,321 | 1,291 | 1,305 | 1,525 | 1,391 |
| Other | 89 | 86 | 88 | 94 | 94 |
| Total retail | 7,738 | 7,772 | 7,727 | 8,240 | 7,620 |
| Wholesale — non-affiliates | 163 | 175 | 215 | 335 | 281 |
| Wholesale — affiliates | 26 | 42 | 20 | 42 | 20 |
| Total revenues from sales of electricity | 7,927 | 7,989 | 7,962 | 8,617 | 7,921 |
| Other revenues | 383 | 394 | 364 | 371 | 353 |
| Total | $8,310 | $8,383 | $8,326 | $8,988 | $8,274 |
| Kilowatt-Hour Sales (in millions): | | | | | |
| Residential | 26,144 | 27,585 | 26,649 | 27,132 | 25,479 |
| Commercial | 32,155 | 32,932 | 32,719 | 32,426 | 31,984 |
| Industrial | 23,518 | 23,746 | 23,805 | 23,549 | 23,087 |
| Other | 584 | 610 | 632 | 633 | 630 |
| Total retail | 82,401 | 84,873 | 83,805 | 83,740 | 81,180 |
| Wholesale — non-affiliates | 3,277 | 3,415 | 3,501 | 4,323 | 3,029 |
| Wholesale — affiliates | 800 | 1,398 | 552 | 1,117 | 496 |
| Total | 86,478 | 89,686 | 87,858 | 89,180 | 84,705 |
| Average Revenue Per Kilowatt-Hour (cents): | | | | | |
| Residential | 12.38 | 12.03 | 12.16 | 12.35 | 12.00 |
| Commercial | 9.62 | 9.34 | 9.46 | 10.09 | 9.62 |
| Industrial | 5.62 | 5.44 | 5.48 | 6.48 | 6.03 |
| Total retail | 9.39 | 9.16 | 9.22 | 9.84 | 9.39 |
| Wholesale | 4.64 | 4.51 | 5.80 | 6.93 | 8.54 |
| Total sales | 9.17 | 8.91 | 9.06 | 9.66 | 9.35 |
| Residential Average Annual Kilowatt-Hour Use Per Customer | 12,028 | 12,864 | 12,582 | 12,969 | 12,293 |
| Residential Average Annual Revenue Per Customer | $1,489 | $1,557 | $1,529 | $1,605 | $1,475 |
| Plant Nameplate Capacity Ratings (year-end) (megawatts) | 15,274 | 15,274 | 15,455 | 17,593 | 17,586 |
| Maximum Peak-Hour Demand (megawatts): | | | | | |
| Winter | 13,894 | 14,527 | 15,735 | 16,308 | 12,767 |
| Summer | 16,002 | 16,244 | 16,104 | 15,777 | 15,228 |
| Annual Load Factor (percent) | 61.1 | 61.9 | 61.9 | 61.2 | 63.5 |
| Plant Availability (percent): | | | | | |
| Fossil-steam | 85.0 | 87.4 | 85.6 | 86.3 | 87.1 |
| Nuclear | 93.5 | 95.6 | 94.1 | 90.8 | 91.8 |
| Source of Energy Supply (percent): | | | | | |
| Oil and gas | 28.6 | 28.2 | 28.3 | 26.3 | 29.6 |
| Coal | 22.4 | 26.4 | 24.5 | 30.9 | 26.4 |
| Nuclear | 17.8 | 17.6 | 17.6 | 16.7 | 17.7 |
| Hydro | 1.0 | 1.1 | 1.6 | 1.3 | 2.0 |
| Other | 0.3 | — | — | — | — |

| | | | | | |
|---|---|---|---|---|---|
| Purchased power — | | | | | |
| From non-affiliates | 7.8 | 6.7 | 5.0 | 3.8 | 3.3 |
| From affiliates | 22.1 | 20.0 | 23.0 | 21.0 | 21.0 |
| Total | 100.0 | 100.0 | 100.0 | 100.0 | 100.0 |

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GULF POWER COMPANY
FINANCIAL SECTION

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MANAGEMENT'S REPORT ON INTERNAL CONTROL OVER FINANCIAL REPORTING
Gulf Power Company 2017 Annual Report

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

Under management's supervision, an evaluation of the design and effectiveness of the Company's internal control over financial reporting was conducted based on the framework in Internal Control—Integrated Framework (2013) issued by the Committee of Sponsoring Organizations of the Treadway Commission. Based on this evaluation, management concluded that the Company's internal control over financial reporting was effective as of December 31, 2017.

/s/ S. W. Connally, Jr.
S. W. Connally, Jr.
Chairman, President, and Chief Executive Officer

/s/ Robin B. Boren
Robin B. Boren
Vice President, Chief Financial Officer, and Treasurer
February 20, 2018

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the stockholder and the Board of Directors of Gulf Power Company

Opinion on the Financial Statements

We have audited the accompanying balance sheets and statements of capitalization of Gulf Power Company (the Company) (a wholly-owned subsidiary of The Southern Company) as of December 31, 2017 and 2016, the related statements of income, comprehensive income, common stockholder's equity, and cash flows for each of the three years in the period ended December 31, 2017, and the related notes (collectively referred to as the "financial statements"). In our opinion, the financial statements (pages II-353 to II-391) 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.

Basis for Opinion

These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on the Company's financial statements 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 audit to obtain reasonable assurance about whether the financial statements are free of material misstatement, whether due to error or fraud. The Company is not required to have, nor were we engaged to perform, an audit of its internal control over financial reporting. As part of our audits, we are required to obtain an understanding of internal control over financial reporting but not for the purpose of expressing an opinion on the effectiveness of the Company's internal control over financial reporting. Accordingly, we express no such opinion. Our audits included performing procedures to assess the risks of material misstatement of the financial statements, whether due to error or fraud, and performing procedures that 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. We believe that our audits provide a reasonable basis for our opinion.

/s/ Deloitte & Touche LLP
Atlanta, Georgia
February 20, 2018

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

DEFINITIONS

| Term | Meaning |
|---|---|
| AFUDC | Allowance for funds used during construction |
| Alabama Power | Alabama Power Company |
| ARO | Asset retirement obligation |
| ASC | Accounting Standards Codification |
| ASU | Accounting Standards Update |
| CCR | Coal combustion residuals |
| Clean Air Act | Clean Air Act Amendments of 1990 |
| $CO_2$ | Carbon dioxide |
| EPA | U.S. Environmental Protection Agency |
| FASB | Financial Accounting Standards Board |
| FERC | Federal Energy Regulatory Commission |
| GAAP | U.S. generally accepted accounting principles |
| Georgia Power | Georgia Power Company |
| IRS | Internal Revenue Service |
| ITC | Investment tax credit |
| KWH | Kilowatt-hour |
| Mississippi Power | Mississippi Power Company |
| mmBtu | Million British thermal units |
| Moody's | Moody's Investors Service, Inc. |
| MW | Megawatt |
| $NO_X$ | Nitrogen oxide |
| OCI | Other comprehensive income |
| power pool | The operating arrangement whereby the integrated generating resources of the traditional electric operating companies and Southern Power (excluding subsidiaries) are subject to joint commitment and dispatch in order to serve their combined load obligations |
| PPA | Power purchase agreement |
| PSC | Public Service Commission |
| ROE | Return on equity |
| S&P | S&P Global Ratings, a division of S&P Global Inc. |
| scrubber | Flue gas desulfurization system |
| SCS | Southern Company Services, Inc. (the Southern Company system service company) |
| SEC | U.S. Securities and Exchange Commission |
| $SO_2$ | Sulfur dioxide |
| Southern Company | The Southern Company |
| Southern Company Gas | Southern Company Gas and its subsidiaries |
| Southern Company system | Southern Company, the traditional electric operating companies, Southern Power, Southern Company Gas (as of July 1, 2016), Southern Electric Generating Company, Southern Nuclear, SCS, Southern Linc, PowerSecure, Inc. (as of May 9, 2016), and other subsidiaries |
| Southern Linc | Southern Communications Services, Inc. |
| Southern Nuclear | Southern Nuclear Operating Company, Inc. |
| Southern Power | Southern Power Company and its subsidiaries |
| 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 |
| traditional electric operating companies | Alabama Power, Georgia Power, Gulf Power Company, and Mississippi Power |

MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS
Gulf Power Company 2017 Annual Report
OVERVIEW
Business Activities
Gulf Power Company (the Company) operates as a vertically integrated utility providing electric service to retail customers within its traditional service territory located in northwest Florida and to wholesale customers in the Southeast.
Many factors affect the opportunities, challenges, and risks of the Company's business of providing electric service. These factors include the ability to maintain a constructive regulatory environment, to maintain and grow energy sales and 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, restoration following major storms, fuel, and capital expenditures. The Company has various regulatory mechanisms that operate to address cost recovery. Effectively operating pursuant to these regulatory mechanisms and appropriately balancing required costs and capital expenditures with customer prices will continue to challenge the Company for the foreseeable future.
On April 4, 2017, the Florida PSC approved a settlement agreement (2017 Rate Case Settlement Agreement) among the Company and three intervenors with respect to the Company's request in 2016 to increase retail base rates. Among the terms of the 2017 Rate Case Settlement Agreement, the Company 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, the Company continued its authorized retail ROE midpoint (10.25%) and range (9.25% to 11.25%), is deemed to have a maximum equity ratio of 52.5% for all retail regulatory purposes, and implemented new dismantlement accruals effective July 1, 2017. The Company 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 the Company'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 the Company'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 the Company's base rates. Under the terms of the 2017 Rate Case Settlement Agreement, by March 1, 2018, the Company 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 the Company's base rates and $15.6 million to the Company'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 the Company'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 the Company 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 the Company'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 the Company'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.

On October 25, 2017, the Florida PSC approved the Company's 2018 annual cost recovery clause factors to provide for a net annual revenue increase of $63 million. See FUTURE EARNINGS POTENTIAL – "Retail Regulatory Matters – Cost Recovery Clauses" herein for additional information.

The Company continues to focus on several key performance indicators including, but not limited to, customer satisfaction, plant availability, system reliability, and net income after dividends on preference stock. The Company's financial success is directly

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tied to customer satisfaction. Key elements of ensuring customer satisfaction include outstanding service, high reliability, and competitive prices. Management uses customer satisfaction surveys to evaluate the Company's results and generally targets the top quartile of these surveys in measuring performance.

See RESULTS OF OPERATIONS herein for information on the Company's financial performance.

Earnings

The Company's 2017 net income after dividends on preference stock was $135 million, representing a $4 million, or 3.1%, increase over the previous year. The increase was primarily due to higher retail base revenues and lower depreciation, partially offset by a write-down of $32.5 million ($20 million after tax) of the Company's ownership of Plant Scherer Unit 3 resulting from the 2017 Rate Case Settlement Agreement and by higher operations and maintenance expenses as compared to the corresponding period in 2016.

In 2016, the net income after dividends on preference stock was $131 million, representing a $17 million, or 11.5%, decrease over the previous year. The decrease was primarily due to lower wholesale revenues and higher depreciation, partially offset by higher retail revenues and lower operations and maintenance expenses as compared to the corresponding period in 2015.

RESULTS OF OPERATIONS

A condensed statement of income follows:

| | Amount | Increase (Decrease) from Prior Year | |
|---|---|---|---|
| | 2017 | 2017 | 2016 |
| | (in millions) | | |
| Operating revenues | $1,516 | $ 31 | $ 2 |
| Fuel | 427 | (5) | (13) |
| Purchased power | 155 | 13 | 7 |
| Other operations and maintenance | 359 | 23 | (18) |
| Depreciation and amortization | 137 | (35) | 31 |
| Taxes other than income taxes | 116 | (4) | 2 |
| Loss on Plant Scherer Unit 3 | 33 | 33 | — |
| Total operating expenses | 1,227 | 25 | 9 |
| Operating income | 289 | 6 | (7) |
| Total other income and (expense) | (60) | (8) | (11) |
| Income taxes | 90 | (1) | (1) |
| Net income | 139 | (1) | (17) |
| Dividends on preference stock | 4 | (5) | — |
| Net income after dividends on preference stock | $135 | $ 4 | $ (17) |

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MANAGEMENT'S DISCUSSION AND ANALYSIS (continued)
Gulf Power Company 2017 Annual Report

Operating Revenues
Operating revenues for 2017 were $1.52 billion, reflecting an increase of $31 million from 2016. Details of operating revenues were as follows:

| | Amount 2017 | 2016 |
|---|---|---|
| | (in millions) | |
| Retail — prior year | $1,281 | $1,249 |
| Estimated change resulting from – | | |
| Rates and pricing | 40 | 30 |
| Sales growth | 2 | — |
| Weather | (11) | 1 |
| Fuel and other cost recovery | (31) | 1 |
| Retail — current year | 1,281 | 1,281 |
| Wholesale revenues – | | |
| Non-affiliates | 57 | 61 |
| Affiliates | 108 | 75 |
| Total wholesale revenues | 165 | 136 |
| Other operating revenues | 70 | 68 |
| Total operating revenues | $1,516 | $1,485 |
| Percent change | 2.1 % | N/M |

N/M - Not meaningful

In 2017, retail revenues remained flat when compared to 2016 primarily due to an increase in retail base revenues effective with the first billing cycle in July 2017, offset by decreases in fuel and purchased power capacity clause revenues and the impact of milder weather. In 2016, retail revenues increased $32 million, or 2.6%, when compared to 2015 primarily as a result of an increase in the Company's environmental cost recovery clause revenues, partially offset by a decrease in the energy conservation clause revenues. See "Energy Sales" below for a discussion of changes in the volume of energy sold, including changes related to sales growth and weather.

In 2017, revenues associated with changes in rates and pricing increased primarily due to an increase in retail base rates effective with the first billing cycle in July 2017. In 2016, revenues associated with changes in rates and pricing increased primarily due to an increase in the environmental cost recovery clause as a result of additional rate base investment related to environmental compliance equipment placed in service at the end of 2015 as well as portions of the Company's ownership in Plant Scherer Unit 3 that were rededicated to retail service in 2016. Annually, the Company petitions the Florida PSC for recovery of projected environmental and energy conservation costs, including any true-up amount from prior periods, and approved rates are implemented each January. The recovery provisions include related expenses and a return on average net investment.

Fuel and other cost recovery provisions include fuel expenses, the energy component of purchased power costs, purchased power capacity costs, the difference between projected and actual costs and revenues related to energy conservation and environmental compliance, and a credit for certain wholesale revenues as a result of the 2017 Rate Case Settlement Agreement. Annually, the Company petitions the Florida PSC for recovery of projected fuel and purchased power costs, including any true-up amount from prior periods, and approved rates are implemented each January. The recovery provisions generally equal the related expenses and have no material effect on earnings.

See Note 1 to the financial statements under "Revenues" and Note 3 to the financial statements under "Retail Regulatory Matters" for additional information regarding the Company's retail base rate cases, cost recovery clauses, and related rate changes.

MANAGEMENT'S DISCUSSION AND ANALYSIS (continued)
Gulf Power Company 2017 Annual Report

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

| | 2017 | 2016 | 2015 |
|---|---|---|---|
| | (in millions) | | |
| Capacity and other | $25 | $ 30 | $67 |
| Energy | 32 | 31 | 40 |
| Total non-affiliated | $57 | $ 61 | $107 |

Wholesale revenues from sales to non-affiliates consist of long-term sales agreements to other utilities in Florida and Georgia and short-term opportunity sales. Capacity revenues from long-term sales agreements represent the greatest contribution to net income. The energy is generally sold at variable cost. Short-term opportunity sales are made at market-based rates that generally provide a margin above the Company's variable cost of energy. Wholesale energy revenues from sales to non-affiliates will vary depending on fuel prices, the market prices of wholesale energy compared to the cost of the Company's and the Southern Company system's generation, demand for energy within the Southern Company system's electric service territory, and the availability of the Southern Company system's generation.

In 2017, wholesale revenues from sales to non-affiliates decreased $4 million, or 6.6%, as compared to the prior year primarily due to a 16.0% decrease in capacity revenues resulting from the expiration of a Plant Scherer Unit 3 long-term sales agreement in 2016. In 2016, wholesale revenues from sales to non-affiliates decreased $46 million, or 43.0%, as compared to the prior year primarily due to a 55.3% decrease in capacity revenues resulting from the expiration of Plant Scherer Unit 3 long-term sales agreements in December 2015 and May 2016.

Wholesale revenues from sales to affiliated companies will vary depending on demand and the availability and cost of generating resources at each company. These affiliate sales are made in accordance with the Intercompany Interchange Contract (IIC), as approved by the FERC. These transactions do not have a significant impact on earnings since the revenue related to these energy sales generally offsets the cost of energy sold. In 2017, wholesale revenues from sales to affiliates increased $33 million, or 44.0%, as compared to the prior year primarily due to a 39.6% increase in KWH sales to affiliates due to the dispatch of the Company's lower cost generation resources to serve system territorial load. In 2016, wholesale revenues from sales to affiliates increased $17 million, or 29.3%, as compared to the prior year primarily due to a 46.1% increase in KWH sales to affiliates due to lower planned unit outages for the Company's generation resources and a 7.9% increase in the price of energy sold to affiliates due to more sales during peak load hours.

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 millions) | | | | |
| Residential | 5,229 | (2.4 )% | (0.1 )% | 1.3 % | (0.2 )% |
| Commercial | 3,814 | (1.4 ) | (0.7 ) | — | (1.5 ) |
| Industrial | 1,740 | (5.0 ) | 1.8 | (5.0 ) | 1.8 |
| Other | 26 | 4.5 | (0.8 ) | 4.5 | (0.8 ) |
| Total retail | 10,809 | (2.5 ) | — | (0.2 )% | (0.3 )% |
| Wholesale | | | | | |
| Non-affiliates | 749 | (0.1 ) | (27.8) | | |
| Affiliates | 3,887 | 39.6 | 46.1 | | |
| Total wholesale | 4,636 | 31.2 | 20.0 | | |
| Total energy sales | 15,445 | 5.7 % | 4.2 % | | |

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 2.5% in 2017 compared to the prior year primarily due to milder weather in the first half of the year, partially offset by customer growth. Weather-adjusted residential KWH sales increased

MANAGEMENT'S DISCUSSION AND ANALYSIS (continued)
Gulf Power Company 2017 Annual Report

primarily due to customer growth. Weather-adjusted commercial KWH sales remained flat as a result of lower customer usage primarily resulting from efficiency improvements in appliances and lighting, offset by customer growth. Industrial KWH sales decreased in 2017 compared to 2016 primarily due to changes in customers' operations and energy efficiency improvements.

Residential and commercial KWH sales decreased in 2016 compared to 2015 due to declining use per customer primarily resulting from energy efficiency improvements, partially offset by customer growth and warmer weather during the third quarter. Industrial KWH sales increased in 2016 compared to 2015 primarily due to decreased customer co-generation, partially offset by changes in customers' operations.

See "Operating Revenues" above for a discussion of significant changes in wholesale sales to non-affiliates and affiliated companies.

Fuel and Purchased Power Expenses

Fuel costs constitute one of the largest expenses for the Company. The mix of fuel sources for generation of electricity is determined primarily by demand, the unit cost of fuel, and the availability of generating units. Additionally, the Company purchases a portion of its electricity needs from the wholesale market.

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

| | 2017 | 2016 | 2015 |
|---|---|---|---|
| Total generation (in millions of KWHs) | 9,310 | 8,259 | 8,629 |
| Total purchased power (in millions of KWHs) | 5,991 | 6,973 | 5,976 |
| Sources of generation (percent) – | | | |
| Coal | 54 | 57 | 57 |
| Gas | 46 | 43 | 43 |
| Cost of fuel, generated (in cents per net KWH) – | | | |
| Coal | 3.14 | 3.68 | 3.88 |
| Gas | 3.55 | 4.17 | 4.22 |
| Average cost of fuel, generated (in cents per net KWH) | 3.32 | 3.89 | 4.03 |
| Average cost of purchased power (in cents per net KWH)(*) | 4.55 | 3.63 | 3.89 |

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

In 2017, total fuel and purchased power expenses were $582 million, an increase of $8 million, or 1.4%, from the prior year costs. The increase was primarily the result of a $6 million net increase due to a higher volume of KWHs generated and purchased and a $2 million net increase due to a higher average cost of fuel and purchased power.

In 2016, total fuel and purchased power expenses were $574 million, a decrease of $6 million, or 1.0%, from the prior year costs. The decrease was primarily the result of a $30 million decrease due to a lower average cost of fuel and purchased power, largely offset by a $24 million increase due to a higher volume of KWHs generated and purchased.

Fuel and purchased power transactions do not have a significant impact on earnings since energy and capacity expenses are generally offset by energy and capacity revenues through the Company's fuel and purchased power capacity cost recovery clauses and long-term wholesale contracts. See Note 3 to the financial statements under "Retail Regulatory Matters – Cost Recovery Clauses – Retail Fuel Cost Recovery" and " – Purchased Power Capacity Recovery" for additional information.

Fuel

Fuel expense was $427 million in 2017, a decrease of $5 million, or 1.2%, from the prior year costs. The decrease was primarily due to a 14.7% decrease in the average cost of fuel per KWH generated due to lower coal and natural gas prices, partially offset by a 12.7% higher volume of KWHs generated due to the dispatch of the Company's lower cost generation resources to serve system territorial load. In 2016, fuel expense was $432 million, a decrease of $13 million, or 2.9%, from the prior year costs. The decrease was primarily due to a 3.5% decrease in the average cost of fuel per KWH generated due to lower coal and natural gas prices and a 4.3% lower volume of KWHs generated due to an increase in KWHs purchased from lower-cost gas-fired PPA resources.

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MANAGEMENT'S DISCUSSION AND ANALYSIS (continued)
Gulf Power Company 2017 Annual Report

Purchased Power
Purchased power expense was $155 million in 2017, an increase of $13 million, or 9.2%, from the prior year. The increase was primarily due to a 25.3% increase in the average cost per KWH purchased, partially offset by a 14.1% decrease in the volume of KWHs purchased. In 2016, purchased power expense was $142 million, an increase of $7 million, or 5.2%, from the prior year. The increase was primarily due to a 16.7% increase in the volume of KWHs purchased, partially offset by a 6.7% decrease in the average cost per KWH purchased resulting from lower energy costs from gas-fired resources.
Energy purchases from non-affiliates and affiliates will vary depending on the market prices of wholesale energy as compared to the cost of the Southern Company system's generation, demand for energy within the Southern Company system's electric service territory, and the availability of the Southern Company system's generation. Affiliate purchases are made in accordance with the IIC or other contractual agreements, as approved by the FERC.
Other Operations and Maintenance Expenses
In 2017, other operations and maintenance expenses increased $23 million, or 6.8%, compared to the prior year primarily due to increases of $7 million in environmental compliance expenses, $6 million in rate case expense amortization related to the 2017 Rate Case Settlement Agreement, $6 million in routine and planned maintenance at generation facilities, and $3 million in energy services expenses. In 2016, other operations and maintenance expenses decreased $18 million, or 5.1%, compared to the prior year primarily due to decreases of $7 million in marketing incentive programs and $6 million in routine and planned maintenance expenses at generation facilities. Also contributing to the decrease was $4 million in rate case expense amortization recorded in 2015 and a $3 million reduction in employee compensation and benefits expenses including pension costs.
Expenses from energy services and marketing incentive programs did not have a significant impact on earnings since they were generally offset by associated revenues. Rate case expenses were amortized as authorized in the 2017 Rate Case Settlement Agreement and a settlement agreement approved by the Florida PSC in 2013 (2013 Rate Case Settlement Agreement). See Note 3 to the financial statements under "Retail Regulatory Matters – Base Rate Cases" and " – Cost Recovery Clauses" and Note 2 to the financial statements for additional information related to rate case expenses and environmental compliance costs and pension costs, respectively.
Depreciation and Amortization
Depreciation and amortization decreased $35 million, or 20.3%, in 2017 compared to the prior year. The decrease was primarily due to the reduction in depreciation of $34.0 million recorded in 2017, as authorized in the 2013 Rate Case Settlement Agreement. In 2016, depreciation and amortization increased $31 million, or 22.0%, compared to the prior year. The increase was primarily due to a reduction in depreciation of $20.1 million recorded in 2015, as authorized in the 2013 Rate Case Settlement Agreement, and an increase of $9 million primarily attributable to property additions to utility plant. See Note 3 to the financial statements under "Retail Regulatory Matters – Retail Base Rate Cases" for additional information.
Total Other Income and (Expense)
In 2017, total other income and (expense) decreased $8 million, or 15.4%, compared to the prior year primarily due to a $5 million increase in donations and a $3 million increase in interest expense, net of amounts capitalized. The increase in interest expense was primarily due to deferred returns on transmission projects in 2016, which reduced interest expense and were recorded as a regulatory asset, as authorized in the 2013 Rate Case Settlement Agreement. In 2016, total other income and (expense) decreased $11 million, or 26.8%, primarily due to a decrease of $13 million in AFUDC equity related to environmental control projects at generating facilities and transmission projects placed in service in 2015, partially offset by a $2 million decrease in interest expense, net of amounts capitalized, primarily due to the redemption of debt. See Note 1 to the financial statements under "Allowance for Funds Used During Construction" for additional information.
Dividends on Preference Stock

Dividends on preference stock decreased $5 million, or 55.6%, in 2017 compared to the prior year due to the redemption of all preference stock in June 2017. See FINANCIAL CONDITION AND LIQUIDITY – "Financing Activities" herein for additional information.

Effects of Inflation

The Company is subject to rate regulation that is generally based on the recovery of historical and projected costs. The effects of inflation can create an economic loss since the recovery of costs could be in dollars that have less purchasing power. Any adverse effect of inflation on the Company's results of operations has not been substantial in recent years.

MANAGEMENT'S DISCUSSION AND ANALYSIS (continued)
Gulf Power Company 2017 Annual Report

FUTURE EARNINGS POTENTIAL
General
The Company operates as a vertically integrated utility providing electric service to retail customers within its traditional service territory located in northwest Florida and to wholesale customers in the Southeast. Prices for electricity provided by the Company to retail customers are set by the Florida PSC under cost-based regulatory principles. Prices for wholesale electricity sales, interconnecting transmission lines, and the exchange of electric power are regulated by the FERC. Retail rates and earnings are reviewed and may be adjusted periodically within certain limitations. See ACCOUNTING POLICIES – "Application of Critical Accounting Policies and Estimates – Utility Regulation" herein and Note 3 to the financial statements under "Retail Regulatory Matters" for additional information about regulatory matters.
The results of operations for the past three years are not necessarily indicative of future earnings potential. The level of the Company's future earnings depends on numerous factors that affect the opportunities, challenges, and risks of the Company's business of providing electric service. These factors include the Company's ability to maintain a constructive regulatory environment that continues to allow for the timely recovery of prudently-incurred costs during a time of increasing costs and limited projected demand growth over the next several years. Future earnings will be driven primarily by customer growth. Earnings will also depend upon maintaining and growing sales, considering, among other things, the adoption and/or penetration rates of increasingly energy-efficient technologies due to changes in the minimum allowable equipment efficiencies along with the continuation of changes in customer behavior, both of which could contribute to a net reduction in customer usage. Earnings are subject to a variety of other factors. These factors include weather, competition, energy conservation practiced by customers, the use of alternative energy sources by customers, the price of electricity, the price elasticity of demand, and the rate of economic growth or decline in the Company's service territory. Demand for electricity is primarily driven by the pace of economic growth that may be affected by changes in regional and global economic conditions, which may impact future earnings.
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.
Environmental Matters
The Company'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 Company 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 Company's 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 or through long-term wholesale agreements. The State of Florida has statutory provisions that allow a utility to petition the Florida PSC for recovery of prudent environmental compliance costs that are not being recovered through base rates or any other recovery mechanism. The

Company's current long-term wholesale agreements contain provisions that permit charging the customer with costs incurred as a result of changes in environmental laws and regulations. Further, increased costs that are recovered through regulated rates could contribute to reduced demand for electricity, which could negatively affect results of operations, cash flows, and financial condition. 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. See "Other Matters" herein and Note 3 to the financial statements under "Retail Regulatory Matters – Cost Recovery Clauses – Environmental Cost Recovery" for additional information, including a discussion on the State of Florida's statutory provisions on environmental cost recovery.

Through 2017, the Company has invested approximately $2.0 billion in environmental capital retrofit projects to comply with environmental requirements, with annual totals of approximately $30 million, $28 million, and $116 million for 2017, 2016, and 2015, respectively. Although the timing, requirements, and estimated costs could change as environmental laws and regulations

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are adopted or modified, as compliance plans are revised or updated, and as legal challenges to rules are initiated or completed, the Company's current compliance strategy estimates capital expenditures of $279 million from 2018 through 2022, with annual totals of approximately $65 million, $57 million, $83 million, $58 million, and $16 million 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 Company 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. No areas within the Company's 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 Company-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 Company has fossil fuel-fired generation subject to these requirements. In October 2016, the EPA published a final rule that revised the CSAPR seasonal $NO_X$ program, which completely removed Florida from all CSAPR programs, left the Georgia seasonal $NO_X$ budget unchanged, and established more stringent $NO_X$ emissions budgets in Mississippi. The outcome of ongoing CSAPR litigation 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 the 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 Florida, Georgia, and Mississippi) 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 Company. The EPA has not yet responded to the SIP

revisions proposed by states where the Company's generating units are located.
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.

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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 Company's 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 and distribution 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.

In addition, numeric nutrient water quality standards promulgated by the State of Florida to limit the amount of nitrogen and phosphorous allowed in state waters are in effect for the State's streams and estuaries. The impact of these standards will depend on further regulatory action in connection with their site-specific implementation through the State of Florida's NPDES permitting program and Total Maximum Daily Load restoration program and cannot be determined at this time.

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.

Based on cost estimates for closure and monitoring of ash ponds pursuant to the CCR Rule, and the closure of an ash pond at Plant Scholz, the Company recorded AROs for each CCR unit in 2015. As further analysis is performed and closure details are developed, the Company will continue to periodically update these cost estimates as necessary. The estimated costs associated with closure of the ash ponds at Plant Scholz and Plant Smith for 2018 have been approved for recovery through the environmental cost recovery clause. 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 the Company's AROs as of December 31, 2017.

Environmental Remediation

The Company 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 Company could incur substantial costs to clean up affected sites. The Company conducts studies to determine the extent of any required cleanup and has recognized the estimated costs to clean up known affected sites in its financial statements. Included in this amount are costs associated with remediation of the Company's substation sites. These projects have been approved by the Florida PSC for recovery through the environmental cost recovery clause; therefore, these liabilities have no impact to the Company's net income. The Company may be liable for some or all required cleanup costs for additional sites that may require environmental remediation. See Note 3 to the financial statements under "Environmental Matters – Environmental Remediation" for additional information.

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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.
The EPA's GHG reporting rule requires annual reporting of GHG emissions expressed in terms of metric tons of $CO_2$ equivalent emissions for a company's operational control of facilities. Based on ownership or financial control of facilities, the Company's 2016 GHG emissions were approximately 8 million metric tons of $CO_2$ equivalent. The preliminary estimate of the Company's 2017 GHG emissions on the same basis is approximately 7 million metric tons of $CO_2$ equivalent.
FERC Matters
The Company has authority from the FERC to sell electricity at market-based rates. Since 2008, that authority, for certain balancing authority areas, has been conditioned on compliance with the requirements of an energy auction, which the FERC found to be tailored mitigation that addresses potential market power concerns. In accordance with FERC regulations governing such authority, the traditional electric operating companies (including the Company) and Southern Power filed a triennial market power analysis in 2014, which included continued reliance on the energy auction as tailored mitigation. In 2015, the FERC issued an order finding that the traditional electric operating companies' (including the Company's) and Southern Power's existing tailored mitigation may not effectively mitigate the potential to exert market power in certain areas served by the traditional electric operating companies and in some adjacent areas. The FERC directed the traditional electric operating companies (including the Company) and Southern Power to show why market-based rate authority should not be revoked in these areas or to provide a mitigation plan to further address market power concerns. The traditional electric operating companies (including the Company) and Southern Power filed a request for rehearing and filed their response with the FERC in 2015.
In December 2016, the traditional electric operating companies (including the Company) and Southern Power filed an amendment to their market-based rate tariff that proposed certain changes to the energy auction, as well as several non-tariff changes. On February 2, 2017, the FERC issued an order accepting all such changes subject to an additional condition of cost-based price caps for certain sales outside of the energy auction, finding that all of these changes would provide adequate alternative mitigation for the traditional electric operating companies' (including the Company's) and Southern Power's potential to exert market power in certain areas served by the traditional electric operating companies (including the Company) and in some adjacent areas. On May 17, 2017, the FERC accepted the traditional electric operating companies' (including the Company's) 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' (including the Company's) and Southern Power's June 29, 2017 triennial updated market power analysis. The FERC directed the traditional electric operating companies (including the Company) 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 (including the Company) 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.

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Retail Regulatory Matters
The Company's rates and charges for service to retail customers are subject to the regulatory oversight of the Florida PSC. The Company's rates are a combination of base rates and several separate cost recovery clauses for specific categories of costs. These separate cost recovery clauses address such items as fuel and purchased energy costs, purchased power capacity costs, energy conservation and demand side management programs, and the costs of compliance with environmental laws and regulations. Costs not addressed through one of the specific cost recovery clauses are recovered through the Company's base rates. See Note 3 to the financial statements under "Retail Regulatory Matters" for additional information.
Retail Base Rate Cases
In the 2013 Rate Case Settlement Agreement, the Florida PSC authorized the Company 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, the Company recognized reductions in depreciation of $8.4 million and $20.1 million, respectively. No net reduction in depreciation was recorded in 2016. In 2017, the Company recognized the remaining $34.0 million reduction in depreciation.
On April 4, 2017, the Florida PSC approved the 2017 Rate Case Settlement Agreement among the Company and three intervenors with respect to the Company's request in 2016 to increase retail base rates. Among the terms of the 2017 Rate Case Settlement Agreement, the Company 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, the Company continued its authorized retail ROE midpoint (10.25%) and range (9.25% to 11.25%), is deemed to have a maximum equity ratio of 52.5% for all retail regulatory purposes, and implemented new dismantlement accruals effective July 1, 2017. The Company also began amortizing the regulatory asset associated with the investment balances remaining after the retirement of Plant Smith Units 1 and 2 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 the Company's ownership of Plant Scherer Unit 3, which was recorded in the first quarter 2017. The remaining issues related to the inclusion of the Company'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 the Company's base rates. Under the terms of the 2017 Rate Case Settlement Agreement, by March 1, 2018, the Company 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 the 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 the Company's base rates and $15.6 million to the Company'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 the Company'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 the Company 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 the Company'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 the Company'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.

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Cost Recovery Clauses
As discussed previously, the 2017 Rate Case Settlement Agreement resolved the remaining issues related to the Company's inclusion of certain costs associated with the ongoing ownership and operation of Plant Scherer Unit 3 in the environmental cost recovery clause and no adjustment to the environmental cost recovery clause rate approved by the Florida PSC in November 2016 was made.
On October 25, 2017, the Florida PSC approved the Company's annual clause rate request for its fuel, purchased power capacity, environmental, and energy conservation cost recovery factors for 2018. The net effect of the approved changes is a $63 million increase in annual revenues effective in January 2018, the majority of which will be offset by related expense increases.
Revenues for all cost recovery clauses, as recorded on the financial statements, are adjusted for differences in actual recoverable costs and amounts billed in current regulated rates. Accordingly, changes in the billing factor for fuel and purchased power will have no significant effect on the Company's revenues or net income, but will affect annual cash flow. The recovery provisions for environmental compliance and energy conservation include related expenses and a return on net average investment. See Note 1 to the financial statements under "Revenues" for additional information.
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.
Regulated utility businesses 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, net operating losses (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 in the subsequent tax year.
For the year ended December 31, 2017, implementation of the Tax Reform Legislation resulted in a $25 million decrease in regulatory assets and a $456 million increase in regulatory liabilities, primarily due to the impact of the reduction of the corporate income tax rate on deferred tax assets and liabilities.
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 Florida PSC and the FERC. On January 31, 2018, SCS, on behalf of the traditional electric operating companies (including the Company), filed with the FERC a reduction to the Company's open access transmission tariff charge for 2018 to reflect the revised federal corporate tax rate. See Note 3 to the financial statements under "Regulatory Matters" for additional information regarding the Company's rate filing to reflect the impacts of the Tax Reform Legislation.
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, approximately $20 million of positive cash flows is expected to result from bonus depreciation for the 2017 tax year and approximately

$10 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. See Note 5 to the financial statements under "Current and Deferred Income Taxes" for additional information.

Other Matters

As a result of the cost to comply with environmental regulations imposed by the EPA, the Company retired its coal-fired generation at Plant Smith Units 1 and 2 in March 2016. In August 2016, the Florida PSC approved the Company's request to reclassify the remaining net book value of Plant Smith Units 1 and 2 and the remaining materials and supplies associated with these units as of the retirement date, totaling approximately $63 million, to a regulatory asset. The Company began amortizing the investment balances over 15 years effective January 1, 2018 in accordance with the 2017 Rate Case Settlement Agreement.

The Company is involved in various other matters being litigated and regulatory matters that could affect future earnings. In addition, the Company is subject to certain claims and legal actions arising in the ordinary course of business. The Company's business activities are subject to extensive governmental regulation related to public health and the environment, such as regulation of air emissions and water discharges. Litigation over environmental issues and claims of various types, including property damage, personal injury, common law nuisance, and citizen enforcement of environmental requirements, such as 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 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 the Company's financial statements. See Note 3 to the financial statements for a discussion of various other contingencies, regulatory matters, and other matters being litigated which may affect future earnings potential.

## ACCOUNTING POLICIES

### Application of Critical Accounting Policies and Estimates

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

### Utility Regulation

The Company is subject to retail regulation by the Florida PSC. The Florida PSC sets the rates the Company is permitted to charge customers based on allowable costs. The Company is also subject to cost-based regulation by the FERC with respect to wholesale transmission rates. As a result, the Company applies accounting standards which require the financial statements to reflect the effects of rate regulation. Through the ratemaking process, the regulators may require the inclusion of costs or revenues in periods different than when they would be recognized by a non-regulated company. This treatment may result in the deferral of expenses and the recording of related regulatory assets based on anticipated future recovery through rates or the deferral of gains or creation of liabilities and the recording of related regulatory liabilities. The application of the accounting standards has a further effect on the Company's financial statements as a result of the estimates of allowable costs used in the ratemaking process. These estimates may differ from those actually incurred by the Company; therefore, the accounting estimates inherent in specific costs such as depreciation, AROs, and pension and other postretirement benefits have less of a direct impact on the Company's results of operations and financial condition than they would on a non-regulated company.

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.

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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, the 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. The 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 "Retail 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 the Company's facilities that are subject to the CCR Rule and to the closure of an ash pond at Plant Scholz. In addition, the Company has retirement obligations related to combustion turbines at its Pea Ridge facility, various landfill sites, a barge unloading dock, asbestos removal, and disposal of polychlorinated biphenyls in certain transformers. The Company also has identified retirement obligations related to certain transmission and distribution facilities, certain wireless communication towers, and certain structures authorized by the U.S. Army Corps of Engineers. However, liabilities for the removal of these assets have not been recorded because the settlement timing for the retirement obligations related to these assets is indeterminable and, therefore, the fair value of the retirement obligations cannot be reasonably estimated. A liability for these AROs will be recognized when sufficient information becomes available to support a reasonable estimation of the ARO.
The 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 for those facilities impacted by the CCR Rule. As further analysis is performed and closure details are developed, the Company 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" for additional information.
Given the significant judgment involved in estimating AROs, the Company considers the liabilities for AROs to be critical accounting estimates.
Pension and Other Postretirement Benefits
The Company's calculation of pension and other postretirement benefits expense is dependent on a number of assumptions. These assumptions include discount rates, healthcare cost trend rates, expected long-term return on plan assets, mortality rates, expected salary and wage increases, and other factors. Components of pension and other postretirement benefits expense include interest and service cost on the pension and other postretirement benefit plans, expected return on plan assets, and amortization of certain unrecognized costs and obligations. Actual results that differ from the assumptions utilized are accumulated and amortized over future periods and, therefore, generally affect recognized expense and the recorded obligation in future periods. While the Company believes that the assumptions used are appropriate, differences in actual experience or significant changes in assumptions would affect its pension

and other postretirement benefits costs and obligations.

Key elements in determining the Company's pension and other postretirement benefit expense are the expected long-term return on plan assets and the discount rate used to measure the benefit plan obligations and the periodic benefit plan expense for future periods. The expected long-term return on pension and other postretirement benefit plan assets is based on the Company's investment strategy, historical experience, and expectations for long-term rates of return that consider external actuarial advice. The Company determines the long-term return on plan assets by applying the long-term rate of expected returns on various asset classes to the Company's target asset allocation. For purposes of determining its liability related to the pension and other postretirement benefit plans, the Company discounts the future related cash flows using a single-point discount rate developed

MANAGEMENT'S DISCUSSION AND ANALYSIS (continued)
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from the weighted average of market-observed yields for high quality fixed income securities with maturities that correspond to expected benefit payments. For 2015 and prior years, the Company computed the interest cost component of its net periodic pension and other postretirement benefit plan expense using the same single-point discount rate. Beginning in 2016, the Company adopted a full yield curve approach for calculating the interest cost component whereby the discount rate for each year is applied to the liability for that specific year. As a result, the interest cost component of net periodic pension and other postretirement benefit plan expense decreased by approximately $4 million in 2016.

A 25 basis point change in any significant assumption (discount rate, salaries, or long-term return on plan assets) would result in a $2 million or less change in total annual benefit expense and a $25 million or less change in projected obligations.

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

Contingent Obligations

The Company is subject to a number of federal and state laws and regulations, as well as other factors and conditions that subject it to environmental, litigation, and other risks. See FUTURE EARNINGS POTENTIAL herein and Note 3 to the financial statements for more information regarding certain of these contingencies. The Company periodically evaluates its exposure to such risks and records reserves for those matters where a non-tax-related loss is considered probable and reasonably estimable. The adequacy of reserves can be significantly affected by external events or conditions that can be unpredictable; thus, the ultimate outcome of such matters could materially affect the Company's results of operations, cash flows, or financial condition.

Recently Issued Accounting Standards

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 the Company's revenue, including energy provided to customers, is from tariff offerings that provide electricity without a defined contractual term, as well as longer-term contractual commitments, including PPAs.

The 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 energy-related derivatives, are excluded from the scope of ASC 606 and, therefore, will be accounted for and disclosed separately from revenues under ASC 606. The 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. The Company applied the modified retrospective method of adoption effective January 1, 2018. The 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. ASU 2016-02 is effective for fiscal years beginning after December 15, 2018 and the Company will adopt the new standard effective January 1, 2019.
The 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, the 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 a PPA, cellular towers, and barges where the Company is the lessee and to outdoor lighting and power distribution equipment where the Company is the lessor. The Company is currently analyzing pole attachment agreements and a lease

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determination has not been made at this time. While the Company has not yet determined the ultimate impact, adoption of ASU 2016-02 is expected to have a significant impact on the Company's balance sheet.

Other

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 the 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. The 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. The Company adopted ASU 2017-12 effective January 1, 2018 with no material impact on its financial statements.

FINANCIAL CONDITION AND LIQUIDITY

Overview

The Company's financial condition remained stable at December 31, 2017. The Company's cash requirements primarily consist of funding ongoing operations, common stock dividends, capital expenditures, and debt maturities. Capital expenditures and other investing activities include investments to meet projected long-term demand requirements, to maintain existing facilities, to comply with environmental regulations including adding environmental modifications to existing generating units, to expand and improve transmission and distribution facilities, and for restoration following major storms. Operating cash flows provide a substantial portion of the Company's cash needs. For the three-year period from 2018 through 2020, the Company's projected common stock dividends, capital expenditures, and debt maturities are expected to exceed operating cash flows. The Company plans to finance future cash needs in excess of its operating cash flows primarily through external security issuances, equity contributions from Southern Company, and borrowings from financial institutions. The Company plans to use commercial paper to manage seasonal variations in operating cash flows and for other working capital needs. The Company intends to continue to monitor its access to short-term and long-term capital markets as well as bank credit agreements to meet future capital and liquidity needs. See "Sources of Capital," "Financing Activities," and "Capital Requirements and Contractual Obligations" herein for additional information.

The Company's investments in the qualified pension plan increased in value as of December 31, 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 plan are anticipated during 2018. See Note 2 to the financial statements under "Pension Plans" for additional information.

Net cash provided from operating activities totaled $356 million in 2017, a decrease of $23 million from 2016, primarily due to decreases in cash flows related to the timing of fossil fuel stock purchases and clause recovery,

partially offset by increases related to voluntary contributions to the qualified pension plan in 2016. Net cash provided from operating activities totaled $379 million in 2016, a decrease of $81 million from 2015, primarily due to decreases in cash flows related to clause recovery and a voluntary contribution to the qualified pension plan, partially offset by the timing of fossil fuel stock purchases.
Net cash used for investing activities totaled $234 million, $180 million, and $281 million for 2017, 2016, and 2015, respectively. The changes in cash used for investing activities were primarily related to gross property additions for environmental, distribution, steam generation, and transmission assets. Funds for the Company's property additions were provided by operating activities, capital contributions, and other financing activities.

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Net cash used for financing activities totaled $150 million in 2017 primarily due to the payment of short-term debt, the payment of common stock dividends, and the redemption of preferred stock, partially offset by the proceeds of the issuance of long-term debt and common stock. Net cash used for financing activities totaled $217 million in 2016 primarily due to the redemptions of long-term debt and the payment of common stock dividends, partially offset by an increase in notes payable. Net cash used for financing activities totaled $144 million in 2015 primarily due to the payment of common stock dividends and redemptions of long-term debt, partially offset by an increase in notes payable and proceeds from the issuance of common stock to Southern Company. 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 primarily reflect the financing activities described above. Other significant changes, which resulted from the Tax Reform Legislation, included an increase in deferred credits related to income taxes and a decrease in accumulated deferred income taxes. See FUTURE EARNINGS POTENTIAL – "Income Tax Matters – Federal Tax Reform Legislation" herein and Notes 3 and 5 to the financial statements under "Retail Regulatory Matters" and "Current and Deferred Income Taxes," respectively, for additional information and related proposed regulatory treatment.

The Company's ratio of common equity to total capitalization plus short-term debt, was 53.5% and 48.3% at December 31, 2017 and 2016, respectively. See Note 6 to the financial statements for additional information.

Sources of Capital

The Company plans to obtain the funds required to meet its future capital needs from sources similar to those used in the past, which were primarily from operating cash flows, external security issuances, borrowings from financial institutions, and equity contributions from Southern Company. However, the amount, type, and timing of any future financings, if needed, will depend upon regulatory approval, prevailing market conditions, and other factors.

The issuance of securities by the Company is subject to annual approval by the Florida PSC. Additionally, with respect to the public offering of securities, the Company files registration statements with the SEC under the Securities Act of 1933, as amended (1933 Act). The amounts of securities authorized by the Florida PSC, as well as the amounts registered under the 1933 Act, are continuously monitored and appropriate filings are made to ensure flexibility in the capital markets.

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

The Company's current liabilities may exceed current assets because of scheduled maturities of long-term debt and the periodic use of short-term debt as a funding source, as well as significant seasonal fluctuations in cash needs.

The Company intends to utilize operating cash flows, external security issuances, and borrowings from financial institutions to fund its short-term capital needs. The Company has substantial cash flow from operating activities and access to the capital markets and financial institutions to meet short-term liquidity needs.

At December 31, 2017, the Company had approximately $28 million 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 | |
|---|---|---|---|---|---|---|---|---|
| 2018 | 2019 | 2020 | Total | Unused | One Year | Two Years | Term Out | No Term Out |
| (in millions) | | | (in millions) | | (in millions) | | (in millions) | |
| $30 | $25 | $225 | $280 | $280 | $45 | $— | $20 | $10 |

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

In November 2017, the Company amended $195 million of its multi-year credit arrangements to extend the maturity dates from 2017 and 2018 to 2020.

Most of these bank credit arrangements contain covenants that limit debt levels and contain cross-acceleration provisions to other indebtedness (including guarantee obligations) of the Company. Such cross-acceleration provisions to other indebtedness would trigger an event of default if the Company defaulted on indebtedness, the payment of which was then accelerated. At December 31, 2017, the Company was in compliance with all such covenants. None of the bank credit arrangements contain material adverse change clauses at the time of borrowings.

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

Most of the unused credit arrangements with banks are allocated to provide liquidity support to the Company's pollution control revenue bonds and commercial paper program. The amount of variable rate pollution control revenue bonds outstanding requiring liquidity support as of December 31, 2017 was approximately $82 million. In addition, at December 31, 2017, the Company had $75 million of fixed rate pollution control revenue bonds outstanding that were required to be remarketed within the next 12 months.

The Company may also meet short-term cash needs through a Southern Company subsidiary organized to issue and sell commercial paper at the request and for the benefit of the Company and the other traditional electric operating companies. Proceeds from such issuances for the benefit of the Company are loaned directly to the Company. The obligations of each traditional electric operating company under these arrangements are several and there is no cross-affiliate credit support. Short-term borrowings are included in notes payable on 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 | $ 45 | 2.0 % | $ 20 | 1.3 % | $ 168 |
| Short-term bank debt | — | — % | 38 | 1.6 % | 100 |
| Total | $ 45 | 2.0 % | $ 58 | 1.5 % | |
| December 31, 2016 | | | | | |
| Commercial paper | $ 168 | 1.1 % | $ 53 | 0.9 % | $ 168 |
| Short-term bank debt | 100 | 1.5 % | 64 | 1.3 % | 100 |
| Total | $ 268 | 1.2 % | $ 117 | 1.1 % | |
| December 31, 2015 | | | | | |
| Commercial paper | $ 142 | 0.7 % | $ 101 | 0.4 % | $ 175 |
| Short-term bank debt | — | — % | 10 | 0.7 % | 40 |
| Total | $ 142 | 0.7 % | $ 111 | 0.4 % | |

(*) Average and maximum amounts are based upon daily balances during the year.

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

Financing Activities

In January 2017, the Company issued 1,750,000 shares of common stock to Southern Company and realized proceeds of $175 million. The proceeds were used for general corporate purposes, including the Company's continuous construction program.

In March 2017, the Company extended the maturity of a $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 May 2017, the Company issued $300 million aggregate principal amount of Series 2017A 3.30% Senior Notes due May 30, 2027. The proceeds, together with other funds, were used to repay at maturity $85 million aggregate principal amount of Series 2007A 5.90% Senior Notes due June 15, 2017; to repay outstanding commercial paper borrowings; to repay a $100 million short-term floating rate bank loan, as discussed above; and to redeem, in June 2017, 550,000 shares ($55 million aggregate liquidation amount) of 6.00% Series Preference Stock, 450,000 shares ($45 million aggregate liquidation amount) of Series 2007A 6.45% Preference Stock, and 500,000 shares ($50 million aggregate liquidation amount) of Series 2013A 5.60% Preference Stock.

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

Credit Rating Risk

At December 31, 2017, the Company did not have any credit arrangements that would require material changes in payment schedules or terminations as a result of a credit rating downgrade.

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

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 Baa3 | $ 167 |
| Below BBB- and/or Baa3 | $ 562 |

Included in these amounts are certain agreements that could require collateral in the event that Alabama Power or Georgia Power has a credit rating change to below investment grade. Generally, collateral may be provided by a Southern Company guaranty, letter of credit, or cash. Additionally, a credit rating downgrade could impact the ability of the Company to access capital markets and would be likely to impact the cost at which it does so.

On March 24, 2017, S&P revised its consolidated credit rating outlook for Southern Company and its subsidiaries (including the Company) from stable to negative.

While it is unclear how the credit rating agencies, the FERC, and the Florida PSC 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, including the Company, may be negatively impacted. The Company intends to work with the Florida PSC, including working towards approval of the 2018 Tax Reform Settlement Agreement, to mitigate the adverse impacts, if any, to certain credit metrics. See Note 3 to the financial statements under "Retail Regulatory Matters" for additional information.

Market Price Risk

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

To mitigate future exposure to changes in interest rates, the Company may enter into derivatives which are designated as hedges. The weighted average interest rate on $82 million of outstanding variable rate long-term debt that has not been hedged at December 31, 2017 was 1.85%. If the Company sustained a 100 basis point change in interest rates for all variable rate long-term debt, the change would not materially affect annualized interest expense at December 31, 2017. See Note 1 to the financial statements under "Financial Instruments" and Note 10 to the financial statements for additional information.

To mitigate residual risks relative to movements in fuel and electricity prices, the Company enters into financial hedge contracts for natural gas purchases and physical fixed-price contracts for the purchase and sale of electricity through the wholesale electricity market. The Company continues to manage a fuel-hedging program implemented per the guidelines of the Florida PSC and the actual cost of fuel is recovered through the retail fuel clause. The Florida PSC extended the moratorium on the Company's fuel-hedging program until January 1, 2021 in connection with the 2017 Rate Case Settlement Agreement. The moratorium does not have an impact on the recovery of existing hedges entered into under the previously-approved hedging program. The

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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, substantially all 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 | $(24) | $(100) |
| Contracts realized or settled | 17 | 49 |
| Current period changes(*) | (14) | 27 |
| Contracts outstanding at the end of the period, assets (liabilities), net | $(21) | $(24) |

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

The net hedge volumes of energy-related derivative contracts were 22 million mmBtu and 51 million mmBtu as of December 31, 2017 and December 31, 2016, respectively.

The weighted average swap contract cost above market prices was approximately $0.95 per mmBtu as of December 31, 2017 and $0.48 per mmBtu as of December 31, 2016. Natural gas settlements are recovered through the Company's fuel cost recovery clause.

At December 31, 2017 and 2016, substantially all of the Company's energy-related derivative contracts were designated as regulatory hedges and were related to the Company's fuel-hedging program. Therefore, gains and losses are initially recorded as regulatory liabilities and assets, respectively, and then are included in fuel expense as they are recovered through the fuel cost recovery clause. Gains and losses on energy-related derivative contracts that are not designated or fail to qualify as hedges are recognized in the statements of income as incurred and were not material for any year presented and the actual cost of fuel is recovered through the retail fuel clause.

The Company uses over-the-counter contracts that are not exchange traded but are fair valued using prices which are market observable, and thus fall into Level 2 of the fair value hierarchy. See Note 9 to the financial statements for further discussion of fair value measurements. The maturities of the energy-related derivative contracts, which are all Level 2 of the fair value hierarchy, at December 31, 2017 were as follows:

| | Fair Value Measurements December 31, 2017 | | | |
|---|---|---|---|---|
| | Total | Maturity | | |
| | Fair Value | Year 1 | Years 2&3 | Years 4&5 |
| | (in millions) | | | |
| Level 1 | $— | $— | $ — | $ — |
| Level 2 | (21) | (14) | (7) | — |
| Level 3 | — | — | — | — |
| Fair value of contracts outstanding at end of period | $(21) | $(14) | $ (7) | $ — |

The Company is exposed to market price risk in the event of nonperformance by counterparties to the energy-related derivative contracts. The Company only enters into agreements and material transactions with counterparties that have investment grade credit ratings by Moody's and S&P, or with counterparties who have posted collateral to cover potential credit exposure. Therefore, the Company does not anticipate market risk exposure from nonperformance by the counterparties. For additional information, see Note 1 to the financial statements under "Financial Instruments" and Note 10 to the financial statements.

Capital Requirements and Contractual Obligations

The construction program of the Company is currently estimated to total $304 million for 2018, $266 million for 2019, $358 million for 2020, $279 million for 2021, and $229 million for 2022. These amounts include capital expenditures related to contractual purchase commitments for capital expenditures covered under long-term service agreements. Estimated capital expenditures to comply with environmental laws and regulations included in these amounts are $65 million, $57 million, $83 million, $58 million, and $16 million 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 Company also anticipates costs associated with closure and monitoring of ash ponds at Plant Scholz and in accordance with the CCR Rule, which are reflected in the Company's ARO liabilities. These costs, which could change as the Company continues to refine its assumptions underlying the cost estimates and evaluate the method and timing of compliance activities, are estimated to be $35 million, $11 million, $12 million, $18 million, and $4 million for the years 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 program is subject to periodic review and revision, and actual construction costs may vary from these estimates because of numerous factors. These factors include: changes in business conditions; changes in load projections; storm impacts; changes in environmental laws and regulations; the outcome of any legal challenges to the environmental rules; changes in generating plants, including unit retirements and replacements and adding or changing fuel sources at existing generating units, to meet regulatory requirements; changes in the expected environmental compliance program; changes in FERC rules and regulations; Florida PSC approvals; changes in legislation; the cost and efficiency of construction labor, equipment, and materials; project scope and design changes; and the cost of capital. In addition, there can be no assurance that costs related to capital expenditures will be fully recovered.

In addition, as discussed in Note 2 to the financial statements, the Company provides postretirement benefits to substantially all employees and funds trusts to the extent required by the FERC and the Florida PSC.

Other funding requirements related to obligations associated with scheduled maturities of long-term debt, as well as the related interest, derivative obligations, leases, pension and post-retirement benefit plans, and other purchase commitments are detailed in the contractual obligations table that follows. See Notes 1, 2, 5, 6, 7, and 10 to the financial statements for additional information.

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Contractual Obligations
Contractual obligations at December 31, 2017 were as follows:

| | 2018 | 2019-2020 | 2021-2022 | After 2022 | Total |
|---|---|---|---|---|---|
| | (in millions) | | | | |
| Long-term debt[(a)] – | | | | | |
| Principal | $— | $175 | $141 | $983 | $1,299 |
| Interest | 48 | 95 | 79 | 554 | 776 |
| Financial derivative obligations[(b)] | 14 | 7 | — | — | 21 |
| Operating leases[(c)] | 8 | 4 | 3 | 4 | 19 |
| Purchase commitments – | | | | | |
| Capital[(d)] | 304 | 594 | 508 | — | 1,406 |
| Fuel[(e)] | 211 | 247 | 132 | 44 | 634 |
| Purchased power[(f)] | 129 | 266 | 275 | 906 | 1,576 |
| Other[(g)] | 16 | 34 | 36 | 119 | 205 |
| Pension and other postretirement benefit plans[(h)] | 5 | 11 | — | — | 16 |
| Total | $735 | $1,433 | $1,174 | $2,610 | $5,952 |

(a) All amounts are reflected based on final maturity dates. The Company plans to continue, when economically feasible, to retire higher-cost securities and replace these obligations with lower-cost capital if market conditions permit. Variable rate interest obligations are estimated based on rates as of 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.

(b) See Notes 1 and 10 to the financial statements for additional information.

(c) Excludes a PPA accounted for as a lease, which is included in "Purchased power."

(d) The Company provides estimated capital expenditures for a five-year period, including capital expenditures associated with environmental regulations. These amounts exclude capital expenditures covered under long-term service agreements, which are reflected in "Other." At December 31, 2017, significant purchase commitments were outstanding in connection with the construction program. See FUTURE EARNINGS POTENTIAL – "Environmental Matters – Environmental Laws and Regulations" for additional information.

(e) Includes commitments to purchase coal and natural gas, as well as the related transportation and storage. In most cases, these contracts contain provisions for price escalation, minimum purchase levels, and other financial commitments. Natural gas purchase commitments are based on various indices at the time of delivery. Amounts reflected for natural gas purchase commitments have been estimated based on the New York Mercantile Exchange future prices at December 31, 2017.

(f) The capacity and transmission related costs associated with PPAs are recovered through the purchased power capacity cost recovery clause. Energy costs associated with PPAs are recovered through the fuel cost recovery clause. See Notes 3 and 7 to the financial statements for additional information.

(g) Includes long-term service agreements and contracts for the procurement of limestone. Long-term service agreements include price escalation based on inflation indices. Limestone costs are recovered through the environmental cost recovery clause. See Note 3 to the financial statements for additional information.

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

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Cautionary Statement Regarding Forward-Looking Statements

The Company's 2017 Annual Report contains forward-looking statements. Forward-looking statements include, among other things, statements concerning retail rates, customer and sales growth, economic conditions, fuel and environmental cost recovery and other rate actions, current and proposed environmental regulations and related compliance plans and estimated expenditures, pending or potential litigation matters, access to sources of capital, projections for the qualified pension plan and postretirement benefit plans contributions, financing activities, start and completion of construction projects, filings with state and federal regulatory authorities, impacts of the Tax Reform Legislation, federal income tax benefits, estimated sales and purchases under power sale and purchase agreements, and estimated construction and other plans and expenditures. In some cases, forward-looking statements can be identified by terminology such as "may," "will," "could," "should," "expects," "plans," "anticipates," "believes," "estimates," "projects," "predicts," "potential," or "continue" or the negative of these terms or other similar terminology. There are various factors that could cause actual results to differ materially from those suggested by the forward-looking statements; accordingly, there can be no assurance that such indicated results will be realized. These factors include:

- the impact of recent and future federal and state regulatory changes, including environmental laws 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 Company is 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 Company;
- 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 Company operates;
- variations in demand for electricity, 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 fuels;
- effects of inflation;
- the ability to control costs and avoid cost overruns during the development and construction of facilities, to construct facilities in accordance with the requirements of permits and licenses, and to satisfy any environmental performance standards;
- investment performance of the Company's employee and retiree benefit plans;
- advances in technology;
- state and federal rate regulations and the impact of pending and future rate cases and negotiations, including rate actions relating to fuel and other cost recovery mechanisms;
- the ability to successfully operate generating, transmission, and distribution facilities and the successful performance of necessary corporate functions;
- internal restructuring or other restructuring options that may be pursued;
- potential business strategies, including acquisitions or dispositions of assets or businesses, which cannot be assured to be completed or beneficial to the Company;
- the ability of counterparties of the Company to make payments as and when due and to perform as required;
- the ability to obtain new short- and long-term contracts with wholesale customers;
- the direct or indirect effect on the Company's business resulting from cyber intrusion or physical attack and the threat of physical attacks;
- interest rate fluctuations and financial market conditions and the results of financing efforts;

- changes in the Company's credit ratings, including impacts on interest rates, access to capital markets, and collateral requirements;
- the impacts of any sovereign financial issues, including impacts on interest rates, access to capital markets, impacts on foreign currency exchange rates, counterparty performance, and the economy in general;
- the ability of the Company to obtain additional generating capacity (or sell excess generating capacity) at competitive prices;

MANAGEMENT'S DISCUSSION AND ANALYSIS (continued)
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- catastrophic events such as fires, earthquakes, explosions, floods, tornadoes, hurricanes and other storms, droughts, pandemic health events such as influenzas, or other similar occurrences;
- the direct or indirect effects on the Company's business resulting from incidents affecting the U.S. electric grid or operation of generating resources;
- the effect of accounting pronouncements issued periodically by standard-setting bodies; and
- other factors discussed elsewhere herein and in other reports filed by the Company from time to time with the SEC.

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

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STATEMENTS OF INCOME
For the Years Ended December 31, 2017, 2016, and 2015
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| | 2017 | 2016 | 2015 |
|---|---|---|---|
| | (in millions) | | |
| Operating Revenues: | | | |
| Retail revenues | $1,281 | $1,281 | $1,249 |
| Wholesale revenues, non-affiliates | 57 | 61 | 107 |
| Wholesale revenues, affiliates | 108 | 75 | 58 |
| Other revenues | 70 | 68 | 69 |
| Total operating revenues | 1,516 | 1,485 | 1,483 |
| Operating Expenses: | | | |
| Fuel | 427 | 432 | 445 |
| Purchased power | 155 | 142 | 135 |
| Other operations and maintenance | 359 | 336 | 354 |
| Depreciation and amortization | 137 | 172 | 141 |
| Taxes other than income taxes | 116 | 120 | 118 |
| Loss on Plant Scherer Unit 3 | 33 | — | — |
| Total operating expenses | 1,227 | 1,202 | 1,193 |
| Operating Income | 289 | 283 | 290 |
| Other Income and (Expense): | | | |
| Interest expense, net of amounts capitalized | (50) | (47) | (49) |
| Other income (expense), net | (10) | (5) | 8 |
| Total other income and (expense) | (60) | (52) | (41) |
| Earnings Before Income Taxes | 229 | 231 | 249 |
| Income taxes | 90 | 91 | 92 |
| Net Income | 139 | 140 | 157 |
| Dividends on Preference Stock | 4 | 9 | 9 |
| Net Income After Dividends on Preference Stock | $135 | $131 | $148 |

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

STATEMENTS OF COMPREHENSIVE INCOME
For the Years Ended December 31, 2017, 2016, and 2015
Gulf Power Company 2017 Annual Report

| | 2017 | 2016 | 2015 |
|---|---|---|---|
| | (in millions) | | |
| Net Income | $139 | $140 | $157 |
| Other comprehensive income (loss): | | | |
| Qualifying hedges: | | | |
| Changes in fair value, net of tax of $(1), $-, and $-, respectively | (1) | 1 | 1 |
| Total other comprehensive income (loss) | (1) | 1 | 1 |
| Comprehensive Income | $138 | $141 | $158 |

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

STATEMENTS OF CASH FLOWS
For the Years Ended December 31, 2017, 2016, and 2015
Gulf Power Company 2017 Annual Report

| | 2017 | 2016 | 2015 |
|---|---|---|---|
| | (in millions) | | |
| Operating Activities: | | | |
| Net income | $139 | $140 | $157 |
| Adjustments to reconcile net income | | | |
| to net cash provided from operating activities — | | | |
| Depreciation and amortization, total | 149 | 179 | 152 |
| Deferred income taxes | 72 | 57 | 90 |
| Pension and postretirement funding | — | (48) | — |
| Loss on Plant Scherer Unit 3 | 33 | — | — |
| Other, net | (3) | (3) | 4 |
| Changes in certain current assets and liabilities — | | | |
| -Receivables | (43) | 15 | 33 |
| -Fossil fuel stock | 8 | 37 | (6) |
| -Prepaid income taxes | 8 | (11) | 32 |
| -Other current assets | (2) | (1) | (2) |
| -Accounts payable | 20 | 5 | (22) |
| -Over recovered regulatory clause revenues | (12) | 1 | 22 |
| -Other current liabilities | (13) | 8 | — |
| Net cash provided from operating activities | 356 | 379 | 460 |
| Investing Activities: | | | |
| Property additions | (202) | (178) | (235) |
| Cost of removal, net of salvage | (21) | (9) | (10) |
| Change in construction payables | (2) | 13 | (28) |
| Other investing activities | (9) | (6) | (8) |
| Net cash used for investing activities | (234) | (180) | (281) |
| Financing Activities: | | | |
| Increase (decrease) in notes payable, net | (223) | 126 | 32 |
| Proceeds — | | | |
| Common stock issued to parent | 175 | — | 20 |
| Capital contributions from parent company | 2 | 20 | 4 |
| Pollution control revenue bonds | — | — | 13 |
| Senior notes | 300 | — | — |
| Redemptions and repurchases — | | | |
| Preference stock | (150) | — | — |
| Senior notes | (85) | (235) | (60) |
| Pollution control revenue bonds | — | — | (13) |
| Payment of common stock dividends | (165) | (120) | (130) |
| Other financing activities | (4) | (8) | (10) |
| Net cash used for financing activities | (150) | (217) | (144) |
| Net Change in Cash and Cash Equivalents | (28) | (18) | 35 |
| Cash and Cash Equivalents at Beginning of Year | 56 | 74 | 39 |
| Cash and Cash Equivalents at End of Year | $28 | $56 | $74 |
| Supplemental Cash Flow Information: | | | |
| Cash paid (received) during the period for — | | | |
| Interest (net of $-, $-, and $6 capitalized, respectively) | $46 | $53 | $52 |

| | | | |
|---|---|---|---|
| Income taxes (net of refunds) | 12 | 21 | (7 ) |
| Noncash transactions — | | | |
| Accrued property additions at year-end | 31 | 33 | 20 |
| Other financing activities related to energy services | (7 ) | — | — |
| Receivables related to energy services | 7 | — | — |

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

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BALANCE SHEETS
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| Assets | 2017 | 2016 |
|---|---|---|
| | (in millions) | |
| Current Assets: | | |
| Cash and cash equivalents | $28 | $56 |
| Receivables — | | |
| Customer accounts receivable | 76 | 72 |
| Unbilled revenues | 67 | 55 |
| Under recovered regulatory clause revenues | 27 | 17 |
| Affiliated | 14 | 17 |
| Other accounts and notes receivable | 7 | 6 |
| Accumulated provision for uncollectible accounts | (1) | (1) |
| Fossil fuel stock | 63 | 71 |
| Materials and supplies | 57 | 55 |
| Other regulatory assets, current | 56 | 44 |
| Other current assets | 21 | 30 |
| Total current assets | 415 | 422 |
| Property, Plant, and Equipment: | | |
| In service | 5,196 | 5,140 |
| Less: Accumulated provision for depreciation | 1,461 | 1,382 |
| Plant in service, net of depreciation | 3,735 | 3,758 |
| Construction work in progress | 91 | 51 |
| Total property, plant, and equipment | 3,826 | 3,809 |
| Deferred Charges and Other Assets: | | |
| Deferred charges related to income taxes | 31 | 58 |
| Other regulatory assets, deferred | 502 | 512 |
| Other deferred charges and assets | 23 | 21 |
| Total deferred charges and other assets | 556 | 591 |
| Total Assets | $4,797 | $4,822 |

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

BALANCE SHEETS
At December 31, 2017 and 2016
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| Liabilities and Stockholder's Equity | 2017 | 2016 |
|---|---|---|
| | (in millions) | |
| Current Liabilities: | | |
| Securities due within one year | $— | $87 |
| Notes payable | 45 | 268 |
| Accounts payable — | | |
| Affiliated | 52 | 59 |
| Other | 75 | 54 |
| Customer deposits | 35 | 35 |
| Accrued taxes — | | |
| Accrued income taxes | 1 | 1 |
| Other accrued taxes | 9 | 19 |
| Accrued interest | 9 | 8 |
| Accrued compensation | 39 | 40 |
| Deferred capacity expense, current | 22 | 22 |
| Other regulatory liabilities, current | — | 16 |
| Asset retirement obligations, current | 37 | 16 |
| Other current liabilities | 27 | 24 |
| Total current liabilities | 351 | 649 |
| Long-Term Debt (See accompanying statements) | 1,285 | 987 |
| Deferred Credits and Other Liabilities: | | |
| Accumulated deferred income taxes | 537 | 948 |
| Deferred credits related to income taxes | 458 | 2 |
| Employee benefit obligations | 102 | 96 |
| Deferred capacity expense | 97 | 119 |
| Asset retirement obligations | 105 | 120 |
| Other cost of removal obligations | 221 | 249 |
| Other regulatory liabilities, deferred | 43 | 45 |
| Other deferred credits and liabilities | 67 | 71 |
| Total deferred credits and other liabilities | 1,630 | 1,650 |
| Total Liabilities | 3,266 | 3,286 |
| Preference Stock (See accompanying statements) | — | 147 |
| Common Stockholder's Equity (See accompanying statements) | 1,531 | 1,389 |
| Total Liabilities and Stockholder's Equity | $4,797 | $4,822 |
| Commitments and Contingent Matters (See notes) | | |

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

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STATEMENTS OF CAPITALIZATION
At December 31, 2017 and 2016
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| | 2017 | 2016 | 2017 | 2016 |
|---|---|---|---|---|
| | (in millions) | | (percent of total) | |
| Long-Term Debt: | | | | |
| Long-term notes payable — | | | | |
| 2.93% to 5.90% due 2017 | $— | $87 | | |
| 4.75% due 2020 | 175 | 175 | | |
| 3.10% due 2022 | 100 | 100 | | |
| 3.30% to 5.10% due 2027-2044 | 715 | 415 | | |
| Total long-term notes payable | 990 | 777 | | |
| Other long-term debt — | | | | |
| Pollution control revenue bonds — | | | | |
| 2.10% due 2022 | 37 | 37 | | |
| 1.15% to 4.45% due 2023-2049 | 190 | 190 | | |
| Variable rate (1.83% at 12/31/17) due 2022 | 4 | 4 | | |
| Variable rates (1.85% to 1.88% at 12/31/17) due 2039-2042 | 78 | 78 | | |
| Total other long-term debt | 309 | 309 | | |
| Unamortized debt discount | (5) | (5) | | |
| Unamortized debt issuance expense | (9) | (7) | | |
| Total long-term debt (annual interest requirement — $48 million) | 1,285 | 1,074 | | |
| Less amount due within one year | — | 87 | | |
| Long-term debt excluding amount due within one year | 1,285 | 987 | 45.6 % | 39.1 % |
| Preferred and Preference Stock: | | | | |
| Authorized — 20,000,000 shares — preferred stock | | | | |
| — 10,000,000 shares — preference stock | | | | |
| Outstanding — $100 par or stated value | | | | |
| — 2017: no shares | | | | |
| — 2016: | | | | |
| — 6.00% preference stock — 550,000 shares (non-cumulative) | — | 54 | | |
| — 6.45% preference stock — 450,000 shares (non-cumulative) | — | 44 | | |
| — 5.60% preference stock — 500,000 shares (non-cumulative) | — | 49 | | |
| Total preference stock | — | 147 | — | 5.8 |
| Common Stockholder's Equity: | | | | |
| Common stock, without par value — | | | | |
| Authorized — 20,000,000 shares | | | | |
| Outstanding — 2017: 7,392,717 shares | | | | |
| — 2016: 5,642,717 shares | 678 | 503 | | |
| Paid-in capital | 594 | 589 | | |
| Retained earnings | 259 | 296 | | |
| Accumulated other comprehensive income | — | 1 | | |
| Total common stockholder's equity | 1,531 | 1,389 | 54.4 | 55.1 |
| Total Capitalization | $2,816 | $2,523 | 100.0% | 100.0% |

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

STATEMENTS OF COMMON STOCKHOLDER'S EQUITY
For the Years Ended December 31, 2017, 2016, and 2015
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| | Number of Common Shares Issued (in millions) | Common Stock | Paid-In Capital | Retained Earnings | Accumulated Other Comprehensive Income (Loss) | Total |
|---|---|---|---|---|---|---|
| Balance at December 31, 2014 | 5 | $ 483 | $ 560 | $ 267 | $ (1) | $1,309 |
| Net income after dividends on preference stock | — | — | — | 148 | — | 148 |
| Issuance of common stock | 1 | 20 | — | — | — | 20 |
| Capital contributions from parent company | — | — | 7 | — | — | 7 |
| Other comprehensive income (loss) | — | — | — | — | 1 | 1 |
| Cash dividends on common stock | — | — | — | (130) | — | (130) |
| Balance at December 31, 2015 | 6 | 503 | 567 | 285 | — | 1,355 |
| Net income after dividends on preference stock | — | — | — | 131 | — | 131 |
| Capital contributions from parent company | — | — | 22 | — | — | 22 |
| Other comprehensive income (loss) | — | — | — | — | 1 | 1 |
| Cash dividends on common stock | — | — | — | (120) | — | (120) |
| Balance at December 31, 2016 | 6 | 503 | 589 | 296 | 1 | 1,389 |
| Net income after dividends on preference stock | — | — | — | 135 | — | 135 |
| Issuance of common stock | — | 175 | — | — | — | 175 |
| Capital contributions from parent company | — | — | 5 | — | — | 5 |
| Other comprehensive income (loss) | — | — | — | — | (1) | (1) |
| Cash dividends on common stock | — | — | — | (165) | — | (165) |
| Other | — | — | — | (7) | — | (7) |
| Balance at December 31, 2017 | 6 | $ 678 | $ 594 | $ 259 | $ — | $1,531 |

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

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1. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES
General
Gulf Power Company (the Company) is a wholly-owned subsidiary of Southern Company, which is the parent company of the Company and three other traditional electric operating companies, as well as Southern Power, Southern Company Gas (as of July 1, 2016), SCS, Southern Linc, Southern Company Holdings, Inc. (Southern Holdings), Southern Nuclear, PowerSecure (as of May 9, 2016), Inc. (PowerSecure), and other direct and indirect subsidiaries. The traditional electric operating companies – the Company, Alabama Power, Georgia Power, and Mississippi Power – are vertically integrated utilities providing electric service in four Southeastern states. The Company provides electric service to retail customers in northwest Florida and to wholesale customers in the Southeast. Southern Power 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 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. PowerSecure is a provider of products and services in the areas of distributed generation, energy efficiency, and utility infrastructure.
The equity method is used for entities in which the Company has significant influence but does not control.
The Company is subject to regulation by the FERC and the Florida PSC. As such, the Company's financial statements reflect the effects of rate regulation in accordance with GAAP and comply with the accounting policies and practices prescribed by its regulatory commissions. The preparation of financial statements in conformity with GAAP requires the use of estimates, and the actual results may differ from those estimates. Certain prior years' data presented in the financial statements have been reclassified to conform to the current year presentation.
Recently Issued Accounting Standards
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 the Company's revenue, including energy provided to customers, is from tariff offerings that provide electricity without a defined contractual term, as well as longer-term contractual commitments, including PPAs.
The 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 energy-related derivatives, are excluded from the scope of ASC 606 and, therefore, will be accounted for and disclosed separately from revenues under ASC 606. The 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. The Company applied the modified retrospective method of adoption effective January 1, 2018. The 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,

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measurement, and presentation of expense associated with leases and provides clarification regarding the identification of certain components of contracts that would represent a lease. The accounting required by lessors is relatively unchanged. ASU 2016-02 is effective for fiscal years beginning after December 15, 2018 and the Company will adopt the new standard effective January 1, 2019.

The 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, the 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 a PPA, cellular towers, and barges where the Company is the lessee and to outdoor lighting and power distribution equipment where the Company is the lessor. The Company is currently analyzing pole attachment agreements and a lease determination has not been made at this time. While the Company has not yet determined the ultimate impact, adoption of ASU 2016-02 is expected to have a significant impact on the 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, the Company recognized any excess tax benefits and deficiencies related to the exercise and vesting of stock compensation as additional paid-in capital. In addition, the new guidance requires excess tax benefits for share-based payments to be included in net cash provided from operating activities rather than net cash provided from financing activities on the statement of cash flows. The Company elected to adopt the guidance in 2016 and reflect the related adjustments as of January 1, 2016. Prior year's data presented in the financial statements has not been adjusted. The Company also elected to recognize forfeitures as they occur. The new guidance did not have a material impact on the results of operations, financial position, or cash flows of the Company. See Notes 5 and 8 for disclosures impacted by ASU 2016-09.

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 the 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. The 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. The Company adopted ASU 2017-12 effective January 1, 2018 with no material impact on its financial statements.

Affiliate Transactions

The Company has an agreement with SCS under which the following services are rendered to the Company at direct or allocated cost: general and design engineering, operations, purchasing, accounting, finance and treasury, tax, information technology, marketing, auditing, insurance and pension administration, human resources, systems and procedures, digital wireless communications, and other services with respect to business and operations, construction management, and power pool transactions. Costs for these services amounted to $81 million, $80 million, and $81 million during 2017, 2016, and 2015, respectively. Cost allocation methodologies used by SCS prior to the repeal of the Public Utility Holding Company Act of 1935, as amended, were approved by the SEC. Subsequently, additional cost allocation methodologies have been reported to the FERC and management believes they are reasonable. The FERC permits services to be rendered at cost by system service companies.

See Note 7 under "Operating Leases" for information on leases of cellular tower space for the Company's digital wireless communications equipment.

The Company has operating agreements with Georgia Power and Mississippi Power under which the Company owns a portion of Plant Scherer and Plant Daniel, respectively. Georgia Power operates Plant Scherer and Mississippi Power operates Plant Daniel. The Company reimbursed Georgia Power $11 million, $8 million, and $12 million and Mississippi Power $31 million, $26 million, and $27 million in 2017, 2016, and 2015, respectively, for its proportionate share of related expenses. See Note 4 and Note 7 under "Operating Leases" for additional information.

Total power purchased from affiliates through the power pool, included in purchased power in the statements of income, totaled $15 million, $16 million, and $35 million in 2017, 2016, and 2015, respectively.

The Company has an agreement with Alabama Power under which Alabama Power made transmission system upgrades to ensure firm delivery of energy under a non-affiliate PPA from a combined cycle plant located in Alabama. Payments by the Company to Alabama Power for the improvements were $11 million, $12 million, and $14 million in 2017, 2016, and 2015, respectively, and are expected to be approximately $10 million annually for 2018 through 2023, when the PPA expires. These costs have been approved for recovery by the Florida PSC through the Company's purchased power capacity cost recovery clause and by the FERC in the transmission facilities cost allocation tariff.

In 2016, the Company purchased a turbine rotor assembly from Southern Power for $6.8 million.

The Company provides incidental services to and receives such services from other Southern Company subsidiaries which are generally minor in duration and amount. Except as described herein, the Company neither provided nor received any material services to or from affiliates in 2017, 2016, or 2015.

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

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Regulatory Assets and Liabilities

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

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

| | 2017 | 2016 | Note |
|---|---|---|---|
| | (in millions) | | |
| Retiree benefit plans, net | $166 | $160 | (a,b) |
| PPA charges | 119 | 141 | (b,c) |
| Closure of ash ponds | 80 | 75 | (b,d) |
| Remaining book value of retired assets | 65 | 66 | (e) |
| Environmental remediation | 52 | 44 | (b,d) |
| Other regulatory assets, net | 36 | 18 | (i) |
| Deferred income tax charges | 31 | 56 | (f) |
| Deferred return on transmission upgrades | 25 | 25 | (e) |
| Fuel-hedging assets, net | 21 | 24 | (b,h) |
| Loss on reacquired debt | 17 | 18 | (j) |
| Asset retirement obligations, net | 13 | 7 | (b,f) |
| Regulatory asset, offset to other cost of removal | — | 29 | (e) |
| Deferred income tax credits | (458) | (2) | (g) |
| Other cost of removal obligations | (221) | (278) | (f) |
| Property damage reserve | (40) | (40) | (e) |
| Over recovered regulatory clause revenues | (11) | (23) | (k) |
| Total regulatory assets (liabilities), net | $(105) | $320 | |

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

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

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

(c) Recovered over the life of the PPA for periods up to six years.

(d) Recovered through the environmental cost recovery clause when the remediation or the work is performed.

(e) Recorded and recovered or amortized as approved by the Florida PSC.

(f) Asset retirement and removal assets and liabilities are recorded, and deferred income tax assets are recorded, recovered, and amortized, over the related property lives, which may range up to 65 years. Asset retirement and removal assets and liabilities will be settled and trued up following completion of the related activities.

(g) Deferred income tax liabilities are amortized over the related property lives, which may range up to 65 years. Includes the deferred tax liabilities as a result of the Tax Reform Legislation. Amortization of $71 million of the deferred tax liabilities at December 31, 2017 is expected to be determined by the Florida PSC at a later date. See Notes 3 and 5 for additional information.

(h) Fuel-hedging assets and liabilities are recorded over the life of the underlying hedged purchase contracts, which currently do not exceed four years. Upon final settlement, actual costs incurred are recovered through the fuel cost recovery clause.

(i) Comprised primarily of under recovered regulatory clause revenues. Other regulatory assets costs, with the exception of vacation pay, are recorded and recovered or amortized as approved by the Florida PSC. Vacation pay, including banked holiday pay, does not earn a return as offset in rate base by a corresponding liability; it is recorded as earned by employees and recovered as paid, generally within one year.

(j) Recovered over either the remaining life of the original issue or, if refinanced, over the life of the new issue, which may range up to 40 years.
(k) Recorded and recovered or amortized as approved by the Florida PSC, generally within one year.

In the event that a portion of the Company's operations is no longer subject to applicable accounting rules for rate regulation, the Company would be required to write off to income or reclassify to accumulated OCI related regulatory assets and liabilities that are not specifically recoverable through regulated rates. In addition, the Company would be required to determine if any impairment to other assets, including plant, exists and write down the assets, if impaired, to their fair values. All regulatory assets and liabilities are to be reflected in rates. See Note 3 under "Retail Regulatory Matters" for additional information.

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Revenues
Wholesale capacity revenues are generally recognized on a levelized basis over the appropriate contract period. Energy and other revenues are recognized as services are provided. Unbilled revenues related to retail sales are accrued at the end of each fiscal period. Electric rates for the Company include provisions to adjust billings for fluctuations in fuel costs, the energy component of purchased power costs, and certain other costs. The Company continuously monitors the over or under recovered fuel cost balance in light of the inherent variability in fuel costs. The Company is required to notify the Florida PSC if the projected fuel cost over or under recovery is expected to exceed 10% of the projected fuel revenue applicable for the period and indicate if an adjustment to the fuel cost recovery factor is being requested. The Company has similar retail cost recovery clauses for energy conservation costs, purchased power capacity costs, and environmental compliance costs. Revenues are adjusted for differences between these actual costs and amounts billed in current regulated rates. Under or over recovered regulatory clause revenues are recorded in the balance sheets and are recovered or returned to customers through adjustments to the billing factors. Annually, the Company petitions for recovery of projected costs including any true-up amounts from prior periods, and approved rates are implemented each January. See Note 3 under "Retail Regulatory Matters" for additional information.
The Company has a diversified base of customers. No single customer or industry comprises 10% or more of revenues. For all periods presented, uncollectible accounts averaged less than 1% of revenues.
Fuel Costs
Fuel costs are expensed as the fuel is used. Fuel expense generally includes fuel transportation costs and the cost of purchased emissions allowances as they are used. Fuel expense and emissions allowance costs are recovered by the Company through the fuel cost recovery and environmental cost recovery rates, respectively, approved annually by the Florida PSC.
Income and Other Taxes
The Company uses the liability method of accounting for deferred income taxes and provides deferred income taxes for all significant income tax temporary differences. Federal ITCs utilized are deferred and amortized to income over the average life of the related property and state ITCs are recognized in the period in which the credit is claimed on the state income tax return. Taxes that are collected from customers on behalf of governmental agencies to be remitted to these agencies are presented net on the statements of income.
The Company recognizes tax positions that are "more likely than not" of being sustained upon examination by the appropriate taxing authorities. See Note 5 under "Unrecognized Tax Benefits" for additional information.
Property, Plant, and Equipment
Property, plant, and equipment is stated at original cost less any regulatory disallowances and impairments. Original cost includes: materials; labor; minor items of property; appropriate administrative and general costs; payroll-related costs such as taxes, pensions, and other benefits; and the interest capitalized and cost of equity funds used during construction.
The Company's property, plant, and equipment in service consisted of the following at December 31:

| | 2017 | 2016 |
|---|---|---|
| | (in millions) | |
| Generation | $3,005 | $3,001 |
| Transmission | 720 | 706 |
| Distribution | 1,282 | 1,241 |
| General | 188 | 191 |
| Plant acquisition adjustment | 1 | 1 |
| Total plant in service | $5,196 | $5,140 |

The cost of replacements of property, exclusive of minor items of property, is capitalized. The cost of maintenance, repairs, and replacement of minor items of property is charged to other operations and maintenance expenses as incurred or performed.

Depreciation and Amortization

Depreciation of the original cost of utility plant in service is provided primarily by using composite straight-line rates, which approximated 3.5% for all years presented. Depreciation studies are conducted periodically to update the composite rates. These studies are approved by the Florida PSC and the FERC. When property subject to depreciation is retired or otherwise disposed of

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in the normal course of business, its original cost, together with the cost of removal, less salvage, is charged to accumulated depreciation. For other property dispositions, the applicable cost and accumulated depreciation are removed from the balance sheet accounts, and a gain or loss is recognized. Minor items of property included in the original cost of the plant are retired when the related property unit is retired. As authorized in a settlement agreement approved by the Florida PSC in 2013 (2013 Rate Case Settlement Agreement), the Company was allowed to reduce depreciation and record a regulatory asset in an aggregate amount up to $62.5 million between January 2014 and June 2017. See Note 3 under "Retail Regulatory Matters – Retail Base Rate Cases" for additional information.

Asset Retirement Obligations and Other Costs of Removal

AROs are computed as the present value of the estimated ultimate costs for an asset's future retirement and are recorded in the period in which the liability is incurred. The costs are capitalized as part of the related long-lived asset and depreciated over the asset's useful life. In the absence of quoted market prices, AROs are estimated using present value techniques in which estimates of future cash outlays associated with the asset retirements are discounted using a credit-adjusted risk-free rate. Estimates of the timing and amounts of future cash outlays are based on projections of when and how the assets will be retired and the cost of future removal activities. The Company has received an order from the Florida PSC allowing the continued accrual of other future retirement costs for long-lived assets that the Company does not have a legal obligation to retire. Accordingly, the accumulated removal costs for these obligations are reflected in the balance sheets as a regulatory liability.

The liability for AROs primarily relates to facilities that are subject to the Disposal of Coal Combustion Residuals from Electric Utilities final rule published by the EPA in 2015 (CCR Rule), principally ash ponds, and to the closure of an ash pond at Plant Scholz. In addition, the Company has retirement obligations related to combustion turbines at its Pea Ridge facility, various landfill sites, a barge unloading dock, asbestos removal, and disposal of polychlorinated biphenyls in certain transformers. The Company also has identified retirement obligations related to certain transmission and distribution facilities, certain wireless communication towers, and certain structures authorized by the U.S. Army Corps of Engineers. However, liabilities for the removal of these assets have not been recorded because the settlement timing for the retirement obligations related to these assets is indeterminable and, therefore, the fair value of the retirement obligations cannot be reasonably estimated. A liability for these AROs will be recognized when sufficient information becomes available to support a reasonable estimation of the ARO. The Company will continue to recognize in the statements of income allowed removal costs in accordance with its regulatory treatment. Any differences between costs recognized in accordance with accounting standards related to asset retirement and environmental obligations and those reflected in rates are recognized as either a regulatory asset or liability, as ordered by the Florida PSC, and are reflected in the balance sheets.

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

| | 2017 | 2016 |
|---|---|---|
| | (in millions) | |
| Balance at beginning of year | $136 | $130 |
| Liabilities incurred | — | 1 |
| Liabilities settled | (8) | (1) |
| Accretion | 2 | 4 |
| Cash flow revisions | 12 | 2 |
| Balance at end of year | $142 | $136 |

The cost estimates for AROs related to CCR 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 for those facilities impacted by the CCR Rule. As further analysis is performed and closure details are developed, the Company will continue to periodically update these cost estimates as necessary.

Allowance for Funds Used During Construction

The Company records AFUDC, which represents the estimated debt and equity costs of capital funds that are necessary to finance the construction of new regulated facilities. While cash is not realized currently, AFUDC increases the revenue requirement and is recovered over the service life of the plant through a higher rate base and higher depreciation. The equity component of AFUDC is not included in calculating taxable income. The average annual AFUDC rate was 5.73% for all years presented. AFUDC, net of income taxes, as a percentage of net income after dividends on preference stock was 0.07%, 0.00%, and 10.8% for 2017, 2016, and 2015, respectively.

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Impairment of Long-Lived Assets and Intangibles
The Company evaluates long-lived assets for impairment when events or changes in circumstances indicate that the carrying value of such assets may not be recoverable. The determination of whether an impairment has occurred is based on either a specific regulatory disallowance or an estimate of undiscounted future cash flows attributable to the assets, as compared with the carrying value of the assets. If an impairment has occurred, the amount of the impairment recognized is determined by either the amount of regulatory disallowance or by estimating the fair value of the assets and recording a loss if the carrying value is greater than the fair value. For assets identified as held for sale, the carrying value is compared to the estimated fair value less the cost to sell in order to determine if an impairment loss is required. Until the assets are disposed of, their estimated fair value is re-evaluated when circumstances or events change.
Property Damage Reserve
The Company accrues for the cost of repairing damages from major storms and other uninsured property damages, including uninsured damages to transmission and distribution facilities, generation facilities, and other property. The costs of such damage are charged to the reserve. The Florida PSC approved annual accrual to the property damage reserve is $3.5 million, with a target level for the reserve between $48 million and $55 million. In accordance with a settlement agreement approved by the Florida PSC on April 4, 2017 (2017 Rate Case Settlement Agreement), the Company suspended further property damage reserve accruals effective April 2017. The Company may make discretionary accruals and is required to resume accruals of $3.5 million annually if the reserve falls below zero. The Company accrued total expenses of $3.5 million in each of 2017, 2016, and 2015. As of December 31, 2017 and 2016, the balance in the Company's property damage reserve totaled approximately $40 million, which is included in other regulatory liabilities, deferred on the balance sheets.
When the property damage reserve is inadequate to cover the cost of major storms, the Florida PSC can authorize a storm cost recovery surcharge to be applied to customer bills. As authorized in the 2017 Rate Case Settlement Agreement, the Company may initiate a storm surcharge to recover costs associated with any tropical systems named by the National Hurricane Center or other catastrophic storm events that reduce the property damage reserve in the aggregate by approximately $31 million (75% of the April 1, 2017 balance) or more. The storm surcharge would begin, on an interim basis, 60 days following the filing of a cost recovery petition, would be limited to $4.00/month for a 1,000 KWH residential customer unless the Company incurs in excess of $100 million in qualified storm recovery costs in a calendar year, and would replenish the property damage reserve to approximately $40 million. See Note 3 under "Retail Regulatory Matters – Retail Base Rate Cases" for additional details of the 2017 Rate Case Settlement Agreement.
Injuries and Damages Reserve
The Company is subject to claims and lawsuits arising in the ordinary course of business. As permitted by the Florida PSC, the Company accrues for the uninsured costs of injuries and damages by charges to income amounting to $1.6 million annually. The Florida PSC has also given the Company the flexibility to increase its annual accrual above $1.6 million to the extent the balance in the reserve does not exceed $2 million and to defer expense recognition of liabilities greater than the balance in the reserve. The cost of settling claims is charged to the reserve. The injuries and damages reserve had a balance of $2.1 million and $1.4 million at December 31, 2017, and 2016, respectively. For 2017, $1.6 million and $0.5 million are included in other current liabilities and other deferred credits and liabilities on the balance sheet, respectively. For 2016, the $1.4 million balance is included in other current liabilities on the balance sheet. There were no liabilities in excess of the reserve balance at December 31, 2017 or 2016.
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 oil, natural gas, coal, transportation, and emissions allowances. Fuel is recorded to inventory when purchased and then expensed, at weighted average cost, as used. Fuel expense and emissions allowance costs are

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recovered by the Company through the fuel cost recovery and environmental cost recovery rates, respectively, approved annually by the Florida PSC. Emissions allowances granted by the EPA are included in inventory at zero cost.

Financial Instruments

The Company uses derivative financial instruments to limit exposure to fluctuations in interest rates, the prices of certain fuel purchases, and electricity purchases and sales. All derivative financial instruments are recognized as either assets or liabilities on the balance sheets (included in "Other" or shown separately as "Risk Management Activities") and are measured at fair value. See Note 9 for additional information regarding fair value. Substantially all of the Company's bulk energy purchases and sales contracts that meet the definition of a derivative are excluded from fair value accounting requirements because they qualify for the "normal" scope exception, and are accounted for under the accrual method. Derivative contracts that qualify as cash flow hedges of anticipated transactions or are recoverable through the Florida PSC approved fuel-hedging program result in the deferral of related gains and losses in OCI or regulatory assets and liabilities, respectively, until the hedged transactions occur. Any ineffectiveness arising from cash flow hedges is recognized currently in net income. Other derivative contracts that qualify as fair value hedges are marked to market through current period income and are recorded on a net basis in the statements of income. Cash flows from derivatives are classified on the statement of cash flows in the same category as the hedged item. The Florida PSC extended the moratorium on the Company's fuel-hedging program until January 1, 2021 in connection with the 2017 Rate Case Settlement Agreement. The moratorium does not have an impact on the recovery of existing hedges entered into under the previously-approved hedging program. See Note 10 for additional information regarding derivatives.

The Company offsets fair value amounts recognized for multiple derivative instruments executed with the same counterparty under a netting arrangement. Additionally, the Company had no outstanding collateral repayment obligations or rights to reclaim collateral arising from derivative instruments recognized at December 31, 2017.

The 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 reclassifications for amounts included in net income.

2. RETIREMENT BENEFITS

The Company has a defined benefit, trusteed, pension plan covering substantially all employees. This qualified pension plan is funded in accordance with requirements of the Employee Retirement Income Security Act of 1974, as amended (ERISA). No contributions to the qualified pension plan were made for the year ended December 31, 2017 and no mandatory contributions to the qualified pension plan are anticipated for the year ending December 31, 2018. The Company also provides certain defined benefit pension plans for a selected group of management and highly compensated employees. Benefits under these non-qualified pension plans are funded on a cash basis. In addition, the Company provides certain medical care and life insurance benefits for retired employees through other postretirement benefit plans. The Company funds its other postretirement trusts to the extent required by the FERC. For the year ending December 31, 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.

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| Assumptions used to determine net periodic costs: | 2017 | 2016 | 2015 |
|---|---|---|---|
| Pension plans | | | |
| Discount rate – benefit obligations | 4.46% | 4.71% | 4.18% |
| Discount rate – interest costs | 3.82 | 3.97 | 4.18 |
| Discount rate – service costs | 4.81 | 5.04 | 4.48 |
| Expected long-term return on plan assets | 7.95 | 8.20 | 8.20 |
| Annual salary increase | 4.46 | 4.46 | 3.59 |
| Other postretirement benefit plans | | | |
| Discount rate – benefit obligations | 4.25% | 4.51% | 4.04% |
| Discount rate – interest costs | 3.56 | 3.68 | 4.04 |
| Discount rate – service costs | 4.62 | 4.88 | 4.38 |
| Expected long-term return on plan assets | 7.81 | 8.05 | 8.07 |
| Annual salary increase | 4.46 | 4.46 | 3.59 |

| Assumptions used to determine benefit obligations: | 2017 | 2016 |
|---|---|---|
| Pension plans | | |
| Discount rate | 3.82% | 4.46% |
| Annual salary increase | 4.46 | 4.46 |
| Other postretirement benefit plans | | |
| Discount rate | 3.69% | 4.25% |
| Annual salary increase | 4.46 | 4.46 |

The Company estimates the expected rate of return on pension plan and other postretirement benefit plan assets using a financial model to project the expected return on each current investment portfolio. The analysis projects an expected rate of return on each of 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:

| | 1 Percent Increase | 1 Percent Decrease |
|---|---|---|
| | (in millions) | |
| Benefit obligation | $ 4 | $ 3 |
| Service and interest costs | — | — |

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Pension Plans

The total accumulated benefit obligation for the pension plans was $524 million at December 31, 2017 and $460 million 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:

| | 2017 | 2016 |
|---|---|---|
| | (in millions) | |
| Change in benefit obligation | | |
| Benefit obligation at beginning of year | $517 | $480 |
| Service cost | 13 | 12 |
| Interest cost | 19 | 19 |
| Benefits paid | (20) | (17) |
| Actuarial (gain) loss | 58 | 23 |
| Balance at end of year | 587 | 517 |
| Change in plan assets | | |
| Fair value of plan assets at beginning of year | 491 | 420 |
| Actual return (loss) on plan assets | 81 | 39 |
| Employer contributions | 1 | 49 |
| Benefits paid | (20) | (17) |
| Fair value of plan assets at end of year | 553 | 491 |
| Accrued liability | $(34) | $(26) |

At December 31, 2017, the projected benefit obligations for the qualified and non-qualified pension plans were $563 million and $25 million, respectively. All pension plan assets are related to the qualified pension plan.

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

| | 2017 | 2016 |
|---|---|---|
| | (in millions) | |
| Other regulatory assets, deferred | $160 | $153 |
| Other current liabilities | (1) | (1) |
| Employee benefit obligations | (33) | (25) |

Presented below are the amounts included in 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.

| | 2017 | 2016 | Estimated Amortization in 2018 |
|---|---|---|---|
| | (in millions) | | |
| Prior service cost | $2 | $3 | $ — |
| Net (gain) loss | 158 | 150 | 10 |
| Regulatory assets | $160 | $153 | |

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The changes in the balance of regulatory assets related to the defined benefit pension plans for the years ended December 31, 2017 and 2016 are presented in the following table:

| | 2017 | 2016 |
|---|---|---|
| | (in millions) | |
| Regulatory assets: | | |
| Beginning balance | $153 | $142 |
| Net (gain) loss | 15 | 16 |
| Change in prior service costs | — | 2 |
| Reclassification adjustments: | | |
| Amortization of prior service costs | (1) | (1) |
| Amortization of net gain (loss) | (7) | (6) |
| Total reclassification adjustments | (8) | (7) |
| Total change | 7 | 11 |
| Ending balance | $160 | $153 |

Components of net periodic pension cost were as follows:

| | 2017 | 2016 | 2015 |
|---|---|---|---|
| | (in millions) | | |
| Service cost | $13 | $12 | $12 |
| Interest cost | 19 | 19 | 20 |
| Expected return on plan assets | (38) | (34) | (32) |
| Recognized net (gain) loss | 7 | 6 | 9 |
| Net amortization | 1 | 1 | 1 |
| Net periodic pension cost | $2 | $4 | $10 |

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:

| | Benefit Payments |
|---|---|
| | (in millions) |
| 2018 | $ 22 |
| 2019 | 23 |
| 2020 | 25 |
| 2021 | 26 |
| 2022 | 28 |
| 2023 to 2027 | 155 |

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

| | 2017 | 2016 |
|---|---|---|
| | (in millions) | |
| Change in benefit obligation | | |
| Benefit obligation at beginning of year | $83 | $81 |
| Service cost | 1 | 1 |
| Interest cost | 3 | 3 |
| Benefits paid | (5) | (4) |
| Actuarial (gain) loss | 1 | 2 |
| Balance at end of year | 83 | 83 |
| Change in plan assets | | |
| Fair value of plan assets at beginning of year | 18 | 17 |
| Actual return (loss) on plan assets | 3 | 2 |
| Employer contributions | 4 | 3 |
| Benefits paid | (5) | (4) |
| Fair value of plan assets at end of year | 20 | 18 |
| Accrued liability | $(63) | $(65) |

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

| | 2017 | 2016 |
|---|---|---|
| | (in millions) | |
| Other regulatory assets, deferred | $8 | $11 |
| Other current liabilities | (1) | (1) |
| Other regulatory liabilities, deferred | (2) | (4) |
| Employee benefit obligations | (62) | (64) |

Approximately $6 million and $7 million was included in net regulatory assets at December 31, 2017 and 2016, respectively, related to the net loss for the other postretirement benefit plans that had not yet been recognized in net periodic other postretirement benefit cost. The estimated amortization of such amounts for 2018 is immaterial.
The changes in the balance of net regulatory assets (liabilities) related to the other postretirement benefit plans for the plan years ended December 31, 2017 and 2016 are presented in the following table:

| | 2017 | 2016 |
|---|---|---|
| | (in millions) | |
| Net regulatory assets (liabilities): | | |
| Beginning balance | $7 | $5 |
| Net (gain) loss | (1) | 2 |
| Ending balance | $6 | $7 |

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

| | 2017 | 2016 | 2015 |
|---|---|---|---|
| | (in millions) | | |
| Service cost | $1 | $1 | $1 |
| Interest cost | 3 | 3 | 3 |
| Expected return on plan assets | (1) | (1) | (1) |
| Net periodic postretirement benefit cost | $3 | $3 | $3 |

Future benefit payments, including prescription drug benefits, reflect expected future service and are estimated based on assumptions used to measure the APBO for the other postretirement benefit plans. Estimated benefit payments are reduced by drug subsidy receipts expected as a result of the Medicare Prescription Drug, Improvement, and Modernization Act of 2003 as follows:

| | Benefit Payments | Subsidy Receipts | Total |
|---|---|---|---|
| | (in millions) | | |
| 2018 | $5 | $ — | $ 5 |
| 2019 | 5 | — | 5 |
| 2020 | 5 | — | 5 |
| 2021 | 6 | (1) | 5 |
| 2022 | 6 | (1) | 5 |
| 2023 to 2027 | 28 | (2) | 26 |

Benefit Plan Assets

Pension plan and other postretirement benefit plan assets are managed and invested in accordance with all applicable requirements, including ERISA and the Internal Revenue Code of 1986, as amended. The Company's investment policies for both the pension plan and the other postretirement benefit plans cover a diversified mix of assets, including equity and fixed income securities, real estate, and private equity. Derivative instruments are used primarily to gain efficient exposure to the various asset classes and as hedging tools. The Company minimizes the risk of large losses primarily through diversification but also monitors and manages other aspects of risk.

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The composition of the Company's pension plan and other postretirement benefit plan assets as of December 31, 2017 and 2016, along with the targeted mix of assets for each plan, is presented below:

| | Target | 2017 | 2016 |
|---|---|---|---|
| Pension plan assets: | | | |
| Domestic equity | 26 % | 31 % | 29 % |
| International equity | 25 | 25 | 22 |
| Fixed income | 23 | 24 | 29 |
| Special situations | 3 | 1 | 2 |
| Real estate investments | 14 | 13 | 13 |
| Private equity | 9 | 6 | 5 |
| Total | 100 % | 100% | 100% |
| Other postretirement benefit plan assets: | | | |
| Domestic equity | 25 % | 30 % | 28 % |
| International equity | 24 | 24 | 21 |
| Domestic fixed income | 25 | 26 | 31 |
| Special situations | 3 | 1 | 2 |
| Real estate investments | 14 | 13 | 13 |
| Private equity | 9 | 6 | 5 |
| Total | 100 % | 100% | 100% |

The investment strategy for plan assets related to the Company's qualified pension plan is to be broadly diversified across major asset classes. The asset allocation is established after consideration of various factors that affect the assets and liabilities of the pension plan including, but not limited to, historical and expected returns and interest rates, volatility, correlations of asset classes, the current level of assets and liabilities, and the assumed growth in assets and liabilities. Because a significant portion of the liability of the pension plan is long-term in nature, the assets are invested consistent with long-term investment expectations for return and risk. To manage the actual asset class exposures relative to the target asset allocation, the Company employs a formal rebalancing program. As additional risk management, external investment managers and service providers are subject to written guidelines to ensure appropriate and prudent investment practices. Management believes the portfolio is well-diversified with no significant concentrations of risk.

Investment Strategies

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

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

Benefit Plan Asset Fair Values

Following are the fair value measurements for the pension plan and the other postretirement benefit plan assets as of December 31, 2017 and 2016. The fair values presented are prepared in accordance with GAAP. For purposes of determining the fair value of the pension plan and other postretirement benefit plan assets and the appropriate level designation, management

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relies on information provided by the plan's trustee. This information is reviewed and evaluated by management with changes made to the trustee information as appropriate.

Valuation methods of the primary fair value measurements disclosed in the following tables are as follows:

- Domestic and international equity. Investments in equity securities such as common stocks, American depositary receipts, and real estate investment trusts that trade on a public exchange are classified as Level 1 investments and are valued at the closing price in the active market. Equity investments with unpublished prices (i.e. pooled funds) are valued as Level 2, when the underlying holdings used to value the investment are comprised of Level 1 or Level 2 equity securities.
- Fixed income. Investments in fixed income securities are generally classified as Level 2 investments and are valued based on prices reported in the market place. Additionally, the value of fixed income securities takes into consideration certain items such as broker quotes, spreads, yield curves, interest rates, and discount rates that apply to the term of a specific instrument.
- Real estate investments, private equity, and special situations investments. Investments in real estate, private equity, and special situations are generally classified as Net Asset Value as a Practical Expedient, since the underlying assets typically do not have publicly available observable inputs. The fund manager values the assets using various inputs and techniques depending on the nature of the underlying investments. Techniques may include purchase multiples for comparable transactions, comparable public company trading multiples, discounted cash flow analysis, prevailing market capitalization rates, recent sales of comparable investments, and independent third-party appraisals. The fair value of partnerships is determined by aggregating the value of the underlying assets less liabilities.

The fair values of pension plan assets as of December 31, 2017 and 2016 are presented below. These fair value measurements exclude cash, receivables related to investment income, pending investments sales, and payables related to pending investment purchases.

| | Fair Value Measurements Using | | | | |
|---|---|---|---|---|---|
| | Quoted Prices in Active Markets for Identical Assets | Significant Other Observable Inputs | Significant Unobservable Inputs | Net Asset Value as a Practical Expedient | |
| As of December 31, 2017: | (Level 1) | (Level 2) | (Level 3) | (NAV) | Total |
| | (in millions) | | | | |
| Assets: | | | | | |
| Domestic equity(*) | $112 | $ 54 | $ — | $ — | $166 |
| International equity(*) | 72 | 65 | — | — | 137 |
| Fixed income: | | | | | |
| U.S. Treasury, government, and agency bonds | — | 39 | — | — | 39 |
| Corporate bonds | — | 57 | — | — | 57 |
| Pooled funds | — | 30 | — | — | 30 |
| Cash equivalents and other | 10 | — | — | — | 10 |
| Real estate investments | 22 | — | — | 55 | 77 |
| Special situations | — | — | — | 8 | 8 |
| Private equity | — | — | — | 31 | 31 |
| Total | $216 | $ 245 | $ — | $ 94 | $555 |

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

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| As of December 31, 2016: | Fair Value Measurements Using Quoted Prices in Active Markets for Identical Assets (Level 1) | Significant Other Observable Inputs (Level 2) | Significant Unobservable Inputs (Level 3) | Net Asset Value as a Practical Expedient (NAV) | Total |
|---|---|---|---|---|---|
| | (in millions) | | | | |
| Assets: | | | | | |
| Domestic equity(*) | $93 | $ 43 | $ — | $ — | $136 |
| International equity(*) | 57 | 52 | — | — | 109 |
| Fixed income: | | | | | |
| U.S. Treasury, government, and agency bonds | — | 27 | — | — | 27 |
| Mortgage- and asset-backed securities | — | 1 | — | — | 1 |
| Corporate bonds | — | 47 | — | — | 47 |
| Pooled funds | — | 24 | — | — | 24 |
| Cash equivalents and other | 46 | — | — | — | 46 |
| Real estate investments | 14 | — | — | 53 | 67 |
| Special situations | — | — | — | 8 | 8 |
| Private equity | — | — | — | 25 | 25 |
| Total | $210 | $ 194 | $ — | $ 86 | $490 |

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

The fair values of 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 investments 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 |
|---|---|---|---|---|---|
| | (in millions) | | | | |
| Assets: | | | | | |
| Domestic equity(*) | $4 | $ 2 | $ — | $ — | $ 6 |
| International equity(*) | 2 | 2 | — | — | 4 |
| Fixed income: | | | | | |
| U.S. Treasury, government, and agency bonds | — | 1 | — | — | 1 |

| | | | | | |
|---|---|---|---|---|---|
| Corporate bonds | — | 2 | — | — | 2 |
| Pooled funds | — | 1 | — | — | 1 |
| Cash equivalents and other | 1 | — | — | — | 1 |
| Real estate investments | 1 | — | — | 2 | 3 |
| Private equity | — | — | — | 1 | 1 |
| Total | $8 | $ 8 | $ — | $ 3 | $ 19 |

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

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| | 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 | $ 2 | $ — | $ — | $ 5 |
| International equity(*) | 2 | 2 | — | — | 4 |
| Fixed income: | | | | | |
| U.S. Treasury, government, and agency bonds | — | 1 | — | — | 1 |
| Corporate bonds | — | 2 | — | — | 2 |
| Pooled funds | — | 1 | — | — | 1 |
| Cash equivalents and other | 2 | — | — | — | 2 |
| Real estate investments | 1 | — | — | 2 | 3 |
| Private equity | — | — | — | 1 | 1 |
| Total | $8 | $ 8 | $ — | $ 3 | $ 19 |

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

Employee Savings Plan

The Company also sponsors a 401(k) defined contribution plan covering substantially all employees. The Company matches a portion of the first 6% of employee base salary contributions. The maximum Company match is 5.1% of an employee's base salary. Total matching contributions made to the plan for 2017, 2016, and 2015 were $5 million, $5 million, and $4 million, respectively.

3. CONTINGENCIES AND REGULATORY MATTERS

General Litigation Matters

The Company is subject to certain claims and legal actions arising in the ordinary course of business. In addition, the Company's business activities are subject to extensive governmental regulation related to public health and the environment, such as regulation of air emissions and water discharges. Litigation over environmental issues and claims of various types, including property damage, personal injury, common law nuisance, and citizen enforcement of environmental requirements such as standards for air, water, land, and protection of 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 the Company cannot be predicted at this time; however, for current proceedings not specifically reported herein, management does not anticipate that the ultimate liabilities, if any, arising from such current proceedings would have a material effect on the Company's financial statements.

Environmental Matters

Environmental Remediation

The Company must comply with environmental laws and regulations governing the handling and disposal of waste and releases of hazardous substances. Under these various laws and regulations, the Company may also incur substantial costs to clean up affected sites. The Company received authority from the Florida PSC to recover approved environmental compliance costs through the environmental cost recovery clause. The Florida PSC reviews costs and adjusts rates up or down annually.

The Company recognizes a liability for environmental remediation costs only when it determines a loss is probable and reasonably estimable. At December 31, 2017 and 2016, the Company's environmental remediation liability included estimated costs of environmental remediation projects of approximately $52 million and $44 million, respectively, of which approximately

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$5 million and $4 million, respectively, is included in under recovered regulatory clause revenues and other current liabilities and approximately $47 million and $40 million, respectively, is included in other regulatory assets, deferred and other deferred credits and liabilities. These estimated costs primarily relate to site closure criteria by the Florida Department of Environmental Protection (FDEP) for potential impacts to soil and groundwater from herbicide applications at the Company's substations. The schedule for completion of the remediation projects is subject to FDEP approval. The projects have been approved by the Florida PSC for recovery through the Company's environmental cost recovery clause; therefore, these liabilities have no impact on net income.

The final outcome of these matters cannot be determined at this time. However, the final disposition of these matters is not expected to have a material impact on the Company's financial statements.

FERC Matters

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

In December 2016, the traditional electric operating companies (including the Company) and Southern Power filed an amendment to their market-based rate tariff that proposed certain changes to the energy auction, as well as several non-tariff changes. On February 2, 2017, the FERC issued an order accepting all such changes subject to an additional condition of cost-based price caps for certain sales outside of the energy auction, finding that all of these changes would provide adequate alternative mitigation for the traditional electric operating companies' (including the Company's) and Southern Power's potential to exert market power in certain areas served by the traditional electric operating companies (including the Company) and in some adjacent areas. On May 17, 2017, the FERC accepted the traditional electric operating companies' (including the Company's) 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' (including the Company's) and Southern Power's June 29, 2017 triennial updated market power analysis. The FERC directed the traditional electric operating companies (including the Company) 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 (including the Company) 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.

Retail Regulatory Matters

The Company's rates and charges for service to retail customers are subject to the regulatory oversight of the Florida PSC. The Company's rates are a combination of base rates and several separate cost recovery clauses for specific categories of costs. These separate cost recovery clauses address such items as fuel and purchased energy costs, purchased power capacity costs, energy conservation and demand side management programs, and the costs of compliance with environmental laws and regulations. Costs not addressed through one of the specific cost recovery clauses are recovered through the Company's base rates.

Retail Base Rate Cases

In the 2013 Rate Case Settlement Agreement, the Florida PSC authorized the Company 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, the Company recognized reductions in depreciation of $8.4 million

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and $20.1 million, respectively. No net reduction in depreciation was recorded in 2016. In 2017, the Company recognized the remaining $34.0 million reduction in depreciation.

On April 4, 2017, the Florida PSC approved the 2017 Rate Case Settlement Agreement among the Company and three intervenors with respect to the Company's request in 2016 to increase retail base rates. Among the terms of the 2017 Rate Case Settlement Agreement, the Company 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, the Company continued its authorized retail ROE midpoint (10.25%) and range (9.25% to 11.25%), is deemed to have a maximum equity ratio of 52.5% for all retail regulatory purposes, and implemented new dismantlement accruals effective July 1, 2017. The Company 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 the Company'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 the Company'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 the Company's base rates. Under the terms of the 2017 Rate Case Settlement Agreement, by March 1, 2018, the Company 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 the Company's base rates and $15.6 million to the Company'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 the Company'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 the Company 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 the Company'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 the Company'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.

Cost Recovery Clauses

As discussed previously, the 2017 Rate Case Settlement Agreement resolved the remaining issues related to the Company's inclusion of certain costs associated with the ongoing ownership and operation of Plant Scherer Unit 3 in the environmental cost recovery clause and no adjustment to the environmental cost recovery clause rate approved by the Florida PSC in November 2016 was made.

On October 25, 2017, the Florida PSC approved the Company's annual clause rate request for its fuel, purchased power capacity, environmental, and energy conservation cost recovery factors for 2018. The net effect of the approved changes is a $63 million increase in annual revenues effective in January 2018, the majority of which will be offset by related expense increases.

Revenues for all cost recovery clauses, as recorded on the financial statements, are adjusted for differences in actual recoverable costs and amounts billed in current regulated rates. Accordingly, changes in the billing factor for fuel and purchased power will have no significant effect on the Company's revenues or net income, but will affect annual cash flow. The recovery provisions for environmental compliance and energy conservation include related expenses and a return on net average investment.

Retail Fuel Cost Recovery

The Company has established fuel cost recovery rates as approved by the Florida PSC. If, at any time during the year, the projected year-end fuel cost over or under recovery balance exceeds 10% of the projected fuel revenue applicable for the period, the Company is required to notify the Florida PSC and indicate if an adjustment to the fuel cost recovery factor is being requested.

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At December 31, 2017, the under recovered fuel balance was approximately $22 million, which is included in under recovered regulatory clause revenues on the balance sheet. At December 31, 2016, the over recovered fuel balance was approximately $15 million, which is included in other regulatory liabilities, current on the balance sheet.

Purchased Power Capacity Recovery

The Company has established purchased power capacity cost recovery rates as approved by the Florida PSC. If the projected year-end purchased power capacity cost over or under recovery balance exceeds 10% of the projected purchased power capacity revenue applicable for the period, the Company is required to notify the Florida PSC and indicate if an adjustment to the purchased power capacity cost recovery factor is being requested.

At December 31, 2017, the under recovered purchased power capacity balance was $2 million, which is included in under recovered regulatory clause revenues on the balance sheet. At December 31, 2016, the balance was immaterial.

Environmental Cost Recovery

The Florida Legislature adopted legislation for an environmental cost recovery clause, which allows an electric utility to petition the Florida PSC for recovery of prudent environmental compliance costs that are not being recovered through base rates or any other recovery mechanism. Such environmental costs include operations and maintenance expenses, emissions allowance expense, depreciation, and a return on net average investment. This legislation also allows recovery of costs incurred as a result of an agreement between the Company and the FDEP for the purpose of ensuring compliance with ozone ambient air quality standards adopted by the EPA.

Annually, the Company seeks recovery of projected costs including any true-up amounts from prior periods. At December 31, 2017 and 2016, the over recovered environmental balance of approximately $11 million and $8 million, respectively, along with the current portion of projected environmental expenditures, was included in under recovered regulatory clause revenues on the balance sheets.

Energy Conservation Cost Recovery

Every five years, the Florida PSC establishes new numeric conservation goals covering a 10-year period for utilities to reduce annual energy and seasonal peak demand using demand-side management (DSM) programs. After the goals are established, utilities develop plans and programs to meet the approved goals. The costs for these programs are recovered through rates established annually in the energy conservation cost recovery (ECCR) clause.

At December 31, 2017, the under recovered ECCR balance was immaterial. At December 31, 2016, the balance was approximately $4 million, which is included in under recovered regulatory clause revenues on the balance sheet.

Other Matters

As a result of the cost to comply with environmental regulations imposed by the EPA, the Company retired its coal-fired generation at Plant Smith Units 1 and 2 in March 2016. In August 2016, the Florida PSC approved the Company's request to reclassify the remaining net book value of Plant Smith Units 1 and 2 and the remaining materials and supplies associated with these units as of the retirement date, totaling approximately $63 million, to a regulatory asset. The Company began amortizing the investment balances over 15 years effective January 1, 2018 in accordance with the 2017 Rate Case Settlement Agreement.

4. JOINT OWNERSHIP AGREEMENTS

The Company and Mississippi Power jointly own Plant Daniel Units 1 and 2, which together represent capacity of 1,000 MWs. Plant Daniel is a generating plant located in Jackson County, Mississippi. In accordance with the operating agreement, Mississippi Power acts as the Company's agent with respect to the construction, operation, and maintenance of these units.

The Company and Georgia Power jointly own the 818-MW capacity Plant Scherer Unit 3. Plant Scherer is a generating plant located near Forsyth, Georgia. In accordance with the operating agreement, Georgia Power acts as the Company's agent with respect to the construction, operation, and maintenance of the unit.

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At December 31, 2017, the Company's percentage ownership and investment in these jointly-owned facilities were as follows:

| | Plant Scherer Unit 3 (coal) | Plant Daniel Units 1 & 2 (coal) |
|---|---|---|
| | (in millions) | |
| Plant in service | $374 | $696 |
| Accumulated depreciation | 147 | 225 |
| Construction work in progress | 9 | 4 |
| Company ownership | 25 % | 50 % |

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

## 5. INCOME TAXES

On behalf of the Company, Southern Company files a consolidated federal income tax return and various combined and separate state income tax returns. Under a joint consolidated income tax allocation agreement, each Southern Company subsidiary's current and deferred tax expense is computed on a stand-alone basis and no subsidiary is allocated more current expense than would be paid if it filed a separate income tax return. In accordance with IRS regulations, each company is jointly and severally liable for the federal tax liability.

### 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, the 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. The 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 "Retail Regulatory Matters" for additional information.

### Current and Deferred Income Taxes

Details of income tax provisions are as follows:

| | 2017 | 2016 | 2015 |
|---|---|---|---|
| | (in millions) | | |
| Federal - | | | |
| Current | $19 | $ 34 | $(3 ) |
| Deferred | 58 | 45 | 80 |
| | 77 | 79 | 77 |
| State - | | | |
| Current | (1 ) | — | 5 |
| Deferred | 14 | 12 | 10 |
| | 13 | 12 | 15 |
| Total | $90 | $ 91 | $92 |

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The tax effects of temporary differences between the carrying amounts of assets and liabilities in the financial statements and their respective tax bases, which give rise to deferred tax assets and liabilities, are as follows:

| | 2017 | 2016 |
|---|---|---|
| | (in millions) | |
| Deferred tax liabilities- | | |
| Accelerated depreciation | $552 | $834 |
| Property basis differences | 105 | 123 |
| Pension and other employee benefits | 38 | 58 |
| Regulatory assets | 22 | 45 |
| Regulatory assets associated with employee benefit obligations | 44 | 65 |
| Regulatory assets associated with asset retirement obligations | 38 | 55 |
| Other | 13 | 12 |
| Total | 812 | 1,192 |
| Deferred tax assets- | | |
| Federal effect of state deferred taxes | 25 | 37 |
| Postretirement benefits | 17 | 26 |
| Pension and other employee benefits | 49 | 72 |
| Property differences | 98 | 1 |
| Regulatory liability associated with Tax Reform Legislation (not subject to normalization) | 19 | — |
| Property reserve | 10 | 17 |
| Asset retirement obligations | 38 | 55 |
| Alternative minimum tax carryforward | 7 | 18 |
| Other | 12 | 18 |
| Total | 275 | 244 |
| Accumulated deferred income taxes | $537 | $948 |

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, tax-related regulatory assets to be recovered from customers were $31 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 $458 million. These liabilities are primarily attributable to deferred taxes previously recognized at rates higher than the current enacted tax law and unamortized ITCs.

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 | 3.7 | 3.4 | 3.9 |
| Non-deductible book depreciation | 0.2 | 0.6 | 0.5 |
| Differences in prior years' deferred and current tax rates | — | (0.1) | (0.1) |
| AFUDC equity | — | — | (1.8) |
| Other, net | 0.5 | 0.6 | (0.6) |
| Effective income tax rate | 39.4% | 39.5% | 36.9% |

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 the Company's overall effective tax rate. See Note 1 under "Recently Issued Accounting Standards" for additional information.

Unrecognized Tax Benefits

The Company has no material unrecognized tax benefits for the periods presented. The Company classifies interest on tax uncertainties as interest expense. Accrued interest for unrecognized tax benefits was immaterial and the Company did not accrue any penalties on uncertain tax positions.

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

The IRS has finalized its audits of Southern Company's consolidated federal income tax returns through 2016. Southern Company is a participant in the Compliance Assurance Process of the IRS. The audits for the Company's state income tax returns have either been concluded, or the statute of limitations has expired, for years prior to 2011.

## 6. FINANCING

### Securities Due Within One Year

At December 31, 2017, the Company had no long-term debt due within one year. At December 31, 2016, the Company had $87 million of long-term debt due within one year.

Maturities through 2022 applicable to total long-term debt include $175 million in 2020 and $141 million in 2022. There are no scheduled maturities in 2018, 2019, or 2021.

### Bank Term Loans

At December 31, 2016, the Company had $100 million of bank term loans outstanding. In March 2017, the Company 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.

### Senior Notes

At December 31, 2017 and 2016, the Company had a total of $990 million and $777 million of senior notes outstanding, respectively. These senior notes are effectively subordinate to all secured debt of the Company, which totaled approximately $41 million at both December 31, 2017 and 2016.

In May 2017, the Company issued $300 million aggregate principal amount of Series 2017A 3.30% Senior Notes due May 30, 2027. The proceeds, together with other funds, were used to repay at maturity $85 million aggregate principal amount of Series 2007A 5.90% Senior Notes due June 15, 2017, to repay outstanding commercial paper borrowings, to repay a $100 million short-term floating rate bank loan, and to redeem, in June 2017, all outstanding shares of preference stock. See "Bank Term Loans" and "Outstanding Classes of Capital Stock" herein for more information.

### Pollution Control Revenue Bonds

Pollution control revenue bond obligations represent loans to the Company from public authorities of funds derived from sales by such authorities of revenue bonds issued to finance pollution control and solid waste disposal facilities. The Company is required to make payments sufficient for the authorities to meet principal and interest requirements of such bonds. The amount of tax-exempt pollution control revenue bond obligations outstanding at December 31, 2017 and 2016 was $309 million.

### Outstanding Classes of Capital Stock

The Company currently has preferred stock, Class A preferred stock, preference stock, and common stock authorized. The Company's preferred stock and Class A preferred stock, without preference between classes, would rank senior to the Company's preference stock and common stock with respect to payment of dividends and voluntary or involuntary dissolution. No shares of preferred stock or Class A preferred stock were outstanding at December 31, 2017. The Company's preference stock would rank senior to the common stock with respect to the payment of dividends and voluntary or involuntary dissolution. No shares of preference stock were outstanding at December 31, 2017. In June 2017, the Company redeemed 550,000 shares ($55 million aggregate liquidation amount) of 6.00% Series Preference Stock, 450,000 shares ($45 million aggregate liquidation amount) of Series 2007A 6.45% Preference Stock, and 500,000 shares ($50 million aggregate liquidation amount) of Series 2013A 5.60% Preference Stock.

In January 2017, the Company issued 1,750,000 shares of common stock to Southern Company and realized proceeds of $175 million. The proceeds were used for general corporate purposes, including the Company's continuous construction program.

Dividend Restrictions

The Company can only pay dividends to Southern Company out of retained earnings or paid-in-capital.

Assets Subject to Lien

The Company has granted a lien on its property at Plant Daniel in connection with the issuance of two series of pollution control revenue bonds with an aggregate outstanding principal amount of $41 million as of December 31, 2017. There are no agreements or other arrangements among the Southern Company system companies under which the assets of one company have been pledged or otherwise made available to satisfy obligations of Southern Company or any of its subsidiaries.

Bank Credit Arrangements

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

| Expires | | | | | Executable Term Loans | | Expires Within One Year | |
|---|---|---|---|---|---|---|---|---|
| 2018 | 2019 | 2020 | Total | Unused | One Year | Two Years | Term Out | No Term Out |
| (in millions) | | | (in millions) | | (in millions) | | (in millions) | |
| $30 | $25 | $225 | $280 | $280 | $45 | $— | $20 | $10 |

In November 2017, the Company amended $195 million of its multi-year credit arrangements to extend the maturity dates from 2017 and 2018 to 2020.

Most of the bank credit arrangements require payment of commitment fees based on the unused portion of the commitments. Commitment fees average less than $^1/_4$ of 1% for the Company.

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

Most of these bank credit arrangements contain covenants that limit the Company's debt level to 65% of total capitalization, as defined in the arrangements. For purposes of these definitions, debt excludes certain hybrid securities. At December 31, 2017, the Company was in compliance with these covenants.

Most of the $280 million of unused credit arrangements with banks provide liquidity support to the Company's pollution control revenue bonds and commercial paper program. The amount of variable rate pollution control revenue bonds outstanding requiring liquidity support as of December 31, 2017 was approximately $82 million. In addition, at December 31, 2017, the Company had $75 million of fixed rate pollution control revenue bonds outstanding that were required to be remarketed within the next 12 months.

For short-term cash needs, the Company borrows primarily through a commercial paper program that has the liquidity support of the Company's committed bank credit arrangements described above. The Company may also borrow through various other arrangements with banks. Commercial paper and short-term bank loans are included in notes payable on the balance sheets.

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Details of short-term borrowings were as follows:

| | Short-term Debt at the End of the Period Amount Outstanding (in millions) | Weighted Average Interest Rate |
|---|---|---|
| December 31, 2017: | | |
| Commercial paper | $45 | 2.0% |
| December 31, 2016: | | |
| Commercial paper | $168 | 1.1% |
| Short-term bank debt | 100 | 1.5% |
| Total | $268 | 1.2% |

7. COMMITMENTS

Fuel and Purchased Power Agreements

To supply a portion of the fuel requirements of its generating plants, the Company has entered into various long-term commitments for the procurement and delivery of fossil fuel which are not recognized on the balance sheets. In 2017, 2016, and 2015, the Company incurred fuel expense of $427 million, $432 million, and $445 million, respectively, the majority of which was purchased under long-term commitments. The Company expects that a substantial amount of its future fuel needs will continue to be purchased under long-term commitments.

In addition, the Company has entered into various long-term commitments for the purchase of capacity, energy, and transmission, some of which are accounted for as operating leases. The energy-related costs associated with PPAs are recovered through the fuel cost recovery clause. The capacity and transmission-related costs associated with PPAs are recovered through the purchased power capacity cost recovery clause. Capacity expense under a PPA accounted for as an operating lease was $75 million each year for 2017, 2016, and 2015.

Estimated total minimum long-term commitments at December 31, 2017 were as follows:

| | Operating Lease PPA (in millions) |
|---|---|
| 2018 | $ 79 |
| 2019 | 79 |
| 2020 | 79 |
| 2021 | 79 |
| 2022 | 79 |
| 2023 and thereafter | 33 |
| Total | $ 428 |

SCS may enter into various types of wholesale energy and natural gas contracts acting as an agent for the Company and all of the other traditional electric operating companies and Southern Power. Under these agreements, each of the traditional electric operating companies and Southern Power may be jointly and severally liable. Accordingly, Southern Company has entered into keep-well agreements with the Company and each of the other traditional electric operating companies to ensure the Company will not subsidize or be responsible for any costs, losses, liabilities, or damages resulting from the inclusion of Southern Power as a contracting party under these agreements.

Operating Leases

In addition to the operating lease PPA discussed above, the Company has entered into operating leases with Southern Linc and other third parties for the use of cellular tower space. These agreements have initial terms ranging from five to 10 years and renewal options of up to five years. The Company also has other operating lease agreements with various terms and expiration dates. Total lease payments were $10 million, $9 million, and $14 million for 2017, 2016, and 2015, respectively. The Company includes any step rents, fixed escalations, and reasonably assured renewal periods in its computation of minimum lease payments.

NOTES (continued)
Gulf Power Company 2017 Annual Report

Estimated total minimum lease payments under these operating leases at December 31, 2017 were as follows:

| | Minimum Lease Payments | | |
|---|---|---|---|
| | Affiliate Operating Leases[a] | Non-Affiliate Operating Leases[b] | Total |
| | (in millions) | | |
| 2018 | $2 | $ 7 | $ 9 |
| 2019 | 1 | 1 | 2 |
| 2020 | 1 | 1 | 2 |
| 2021 | 1 | — | 1 |
| 2022 | 1 | — | 1 |
| 2023 and thereafter | 4 | 1 | 5 |
| Total | $10 | $ 10 | $ 20 |

(a) Includes operating leases for cellular tower space.
(b) Includes operating leases for barges, facilities, and other equipment.

The Company also has operating lease agreements for railcars, barges, and towboats for the transport of coal. The Company has the option to renew the leases at the end of the lease term. The Company's lease costs, charged to fuel inventory and recovered through the retail fuel cost recovery clause, were $7 million in 2017, $5 million in 2016, and $10 million in 2015. The Company's annual barge and towboat payments for 2018 are expected to be approximately $6 million.

## 8. STOCK COMPENSATION

### Stock-Based Compensation

Stock-based compensation primarily in the form of Southern Company performance share units and restricted stock units may be granted through the Omnibus Incentive Compensation Plan to a large segment of the Company's employees ranging from line management to executives. 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 168 current and former employees participating in the stock option, performance share unit, and restricted stock unit programs.

### 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. The Company recognizes compensation expense on a straight-line basis over the three-year performance period without remeasurement.

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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.

For the years ended December 31, 2017, 2016, and 2015, employees of the Company were granted performance share units of 28,423, 57,333, and 48,962, respectively. The weighted average grant-date fair value of TSR-based performance share units granted during 2017, 2016, and 2015, determined using a Monte Carlo simulation model to estimate the TSR of Southern Company's stock among the industry peers over the performance period, was $47.30, $45.18, and $46.38, respectively. The weighted average grant-date fair value of both EPS-based and ROE-based performance share units granted during 2017, 2016, and 2015 was $49.18, $48.83, and $47.75, respectively.

For the years ended December 31, 2017, 2016, and 2015, total compensation cost for performance share units recognized in income and the related tax benefit also recognized in income was immaterial. The compensation cost related to the grant of Southern Company performance share units to the Company's employees is recognized in the Company's financial statements with a corresponding credit to equity, representing a capital contribution from Southern Company. As of December 31, 2017, total unrecognized compensation cost related to performance share award units was immaterial.

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.

For the year ended December 31, 2017, employees of the Company were granted 15,736 restricted stock units. The weighted average grant-date fair value of restricted stock units granted during 2017 was $48.88.

For the year ended December 31, 2017, total compensation cost and the related tax benefit for restricted stock units recognized in income was immaterial. As of December 31, 2017, total unrecognized compensation cost related to restricted stock units was immaterial.

Stock Options

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

The compensation cost related to the grant of Southern Company stock options to the Company's employees is recognized in the Company's financial statements with a corresponding credit to equity, representing a capital contribution from Southern Company. Compensation cost and related tax benefits recognized in the Company's financial statements were not material for any year presented. As of December 31, 2017, all compensation cost related to stock option awards has been recognized.

The total intrinsic value of options exercised during the years ended December 31, 2017, 2016, and 2015 was $2 million, $3 million, and $2 million, respectively. No cash proceeds are received by the Company upon the exercise of stock options. The actual tax benefit realized by the Company for the tax deductions from stock option exercises were immaterial for all years presented. Prior to the adoption of ASU 2016-09 in 2016, the excess tax benefits related to the exercise of stock options were recognized in the Company's financial statements with a credit to equity. Upon the adoption of ASU 2016-09, beginning in 2016,

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all tax benefits related to the exercise of stock options are recognized in income. As of December 31, 2017, the aggregate intrinsic value for the options outstanding and exercisable was $3 million.

## 9. FAIR VALUE MEASUREMENTS

Fair value measurements are based on inputs of observable and unobservable market data that a market participant would use in pricing the asset or liability. The use of observable inputs is maximized where available and the use of unobservable inputs is minimized for fair value measurement and reflects a three-tier fair value hierarchy that prioritizes inputs to valuation techniques used for fair value measurement.

- Level 1 consists of observable market data in an active market for identical assets or liabilities.
- Level 2 consists of observable market data, other than that included in Level 1, that is either directly or indirectly observable.
- Level 3 consists of unobservable market data. The input may reflect the assumptions of the Company of what a market participant would use in pricing an asset or liability. If there is little available market data, then the Company's own assumptions are the best available information.

In the case of multiple inputs being used in a fair value measurement, the lowest level input that is significant to the fair value measurement represents the level in the fair value hierarchy in which the fair value measurement is reported.
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) | Total |
| | (in millions) | | | |
| Assets: | | | | |
| Cash equivalents | $21 | $ — | $ — | $ 21 |
| Liabilities: | | | | |
| Energy-related derivatives | $— | $ 21 | $ — | $ 21 |

As of December 31, 2016, assets and liabilities measured at fair value on a recurring basis during the period, together with their associated level of the fair value hierarchy, were as follows:

| | Fair Value Measurements Using | | | |
|---|---|---|---|---|
| As of December 31, 2016: | Quoted Prices in Active Markets for Identical Assets (Level 1) | Significant Other Observable Inputs (Level 2) | Significant Unobservable Inputs (Level 3) | Total |

| | | | | |
|---|---|---|---|---|
| | (in millions) | | | |
| Assets: | | | | |
| Energy-related derivatives | $— | $ 5 | $ — | $ 5 |
| Cash equivalents | 20 | — | — | 20 |
| Total | $20 | $ 5 | $ — | $ 25 |
| Liabilities: | | | | |
| Energy-related derivatives | $— | $ 29 | $ — | $ 29 |

Valuation Methodologies

The energy-related derivatives primarily consist of over-the-counter financial products for natural gas and physical power products, including, from time to time, basis swaps. These are standard products used within the energy industry and are valued using the market approach. The inputs used are mainly from observable market sources, such as forward natural gas prices, power prices, implied volatility, and overnight index swap interest rates. Interest rate derivatives are also standard over-the-counter

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products that are valued using observable market data and assumptions commonly used by market participants. The fair value of interest rate derivatives reflect the net present value of expected payments and receipts under the swap agreement based on the market's expectation of future interest rates. Additional inputs to the net present value calculation may include the contract terms, counterparty credit risk, and occasionally, implied volatility of interest rate options. The interest rate derivatives are categorized as Level 2 under Fair Value Measurements as these inputs are based on observable data and valuations of similar instruments. See Note 10 for additional information on how these derivatives are used.

As of December 31, 2017 and 2016, other financial instruments for which the carrying amount did not equal fair value were as follows:

| | Carrying Amount | Fair Value |
|---|---|---|
| | (in millions) | |
| Long-term debt: | | |
| 2017 | $1,285 | $1,334 |
| 2016 | $1,074 | $1,097 |

The fair values are determined using Level 2 measurements and are based on quoted market prices for the same or similar issues or on the current rates available to the Company.

10. DERIVATIVES

The Company is exposed to market risks, primarily commodity price risk and interest rate risk. To manage the volatility attributable to these exposures, the Company nets its exposures, where possible, to take advantage of natural offsets and may enter into various derivative transactions for the remaining exposures pursuant to the Company's policies in areas such as counterparty exposure and risk management practices. The Company's policy is that derivatives are to be used primarily for hedging purposes and mandates strict adherence to all applicable risk management policies. Derivative positions are monitored using techniques including, but not limited to, market valuation, value at risk, stress testing, and sensitivity analysis. Derivative instruments are recognized at fair value in the balance sheets as either assets or liabilities and are presented on a net basis. See Note 9 for additional information. In the statements of cash flows, the cash impacts of settled energy-related and interest rate derivatives are recorded as operating activities.

Energy-Related Derivatives

The Company enters into energy-related derivatives to hedge exposures to electricity, gas, and other fuel price changes. However, due to cost-based rate regulations and other various cost recovery mechanisms, the Company has limited exposure to market volatility in energy-related commodity prices. The Company manages fuel-hedging programs, implemented per the guidelines of the Florida PSC, through the use of financial derivative contracts, which is expected to continue to mitigate price volatility. The Florida PSC approved a stipulation and agreement that prospectively imposed a moratorium on the Company's fuel-hedging program in October 2016 through December 31, 2017. In connection with the 2017 Rate Case Settlement Agreement, the Florida PSC extended the moratorium on the Company's fuel-hedging program until January 1, 2021. The moratorium does not have an impact on the recovery of existing hedges entered into under the previously-approved hedging program.

Energy-related derivative contracts are accounted for under one of three methods:

- Regulatory Hedges — Energy-related derivative contracts which are designated as regulatory hedges relate primarily to the Company's fuel-hedging programs, where gains and losses are initially recorded as regulatory liabilities and assets, respectively, and then are included in fuel expense as the underlying fuel is used in operations and ultimately recovered through the fuel cost recovery clause.
- Cash Flow Hedges — Gains and losses on energy-related derivatives designated as cash flow hedges (which are mainly used to hedge anticipated purchases and sales) are initially deferred in OCI before being recognized in the statements of income in the same period as the hedged transactions are reflected in earnings.

- Not Designated — Gains and losses on energy-related derivative contracts that are not designated or fail to qualify as hedges are recognized in the statements of income as incurred.

Some energy-related derivative contracts require physical delivery as opposed to financial settlement, and this type of derivative is both common and prevalent within the electric industry. When an energy-related derivative contract is settled physically, any cumulative unrealized gain or loss is reversed and the contract price is recognized in the respective line item representing the actual price of the underlying goods being delivered.

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At December 31, 2017, the net volume of energy-related derivative contracts for natural gas positions totaled 22 million mmBtu for the Company, with the longest hedge date of 2020 over which it is hedging its exposure to the variability in future cash flows for forecasted transactions.

In addition to the volume discussed above, the Company enters into physical natural gas supply contracts that provide the option to sell back excess gas due to operational constraints. The maximum expected volume of natural gas subject to such a feature is 3 million mmBtu for the Company.

Interest Rate Derivatives

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

At December 31, 2017, there were no interest rate derivatives outstanding.

The estimated pre-tax losses related to interest rate derivatives that will be reclassified from accumulated OCI to interest expense for the 12-month period ending December 31, 2018 are immaterial. The Company has deferred gains and losses that are expected to be amortized into earnings through 2026.

Derivative Financial Statement Presentation and Amounts

The Company enters into energy-related and interest rate derivative contracts that may contain certain provisions that permit intra-contract netting of derivative receivables and payables for routine billing and offsets related to events of default and settlements. 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 was reflected on the balance sheets as follows:

| Derivative Category and Balance Sheet Location | 2017 Assets | 2017 Liabilities | 2016 Assets | 2016 Liabilities |
|---|---|---|---|---|
| | (in millions) | | | |
| Derivatives designated as hedging instruments for regulatory purposes | | | | |
| Energy-related derivatives: | | | | |
| Other current assets/Other current liabilities | $ — | $ 14 | $ 4 | $ 12 |
| Other deferred charges and assets/Other deferred credits and liabilities | — | 7 | 1 | 17 |
| Total derivatives designated as hedging instruments for regulatory purposes | $ — | $ 21 | $ 5 | $ 29 |
| Gross amounts recognized | $ — | $ 21 | $ 5 | $ 29 |
| Gross amounts offset | $ — | $ — | $ (4) | $ (4) |
| Net amounts recognized on the Balance Sheets | $ — | $ 21 | $ 1 | $ 25 |

Energy-related derivatives not designated as hedging instruments were immaterial on the balance sheets for 2017 and 2016.

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:

| Derivative Category | Unrealized Losses Balance Sheet Location | 2017 | 2016 | Unrealized Gains Balance Sheet Location | 2017 | 2016 |
|---|---|---|---|---|---|---|
| | | (in millions) | | | (in millions) | |
| Energy-related derivatives:(*) | Other regulatory assets, current | $(14) | $(9) | Other regulatory liabilities, current | $ — | $ 1 |
| | Other regulatory assets, deferred | (7) | (16) | Other regulatory liabilities, deferred | — | — |
| Total energy-related derivative gains (losses) | | $(21) | $(25) | | $ — | $ 1 |

(*) The unrealized gains and losses for derivative contracts subject to netting arrangements were presented net on the balance sheets.

For the years ended December 31, 2017, 2016, and 2015, the pre-tax effects of energy-related derivatives and interest rate derivatives designated as cash flow hedging instruments on the statements of income were immaterial and 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 energy-related derivatives not designated as hedging instruments on the statements of income were not material.

Contingent Features

The Company does not have any credit arrangements that would require material changes in payment schedules or terminations as a result of a credit rating downgrade. There are certain derivatives that could require collateral, but not accelerated payment, in the event of various credit rating changes of certain affiliated companies. At December 31, 2017, the Company had no collateral posted with its derivative counterparties to satisfy these arrangements.

At December 31, 2017, the fair value of derivative liabilities with contingent features was immaterial. However, because of joint and several liability features underlying these derivatives, the maximum potential collateral requirements arising from the credit-risk related contingent features, at a rating below BBB- and /or Baa3, were $12 million, and include certain agreements that could require collateral in the event that one or more Southern Company system power pool participants has a credit rating change to below investment grade.

Generally, collateral may be provided by a Southern Company guaranty, letter of credit, or cash. If collateral is required, fair value amounts recognized for the right to reclaim cash collateral or the obligation to return cash collateral are not offset against fair value amounts recognized for derivatives executed with the same counterparty.

The Company is exposed to losses related to financial instruments in the event of counterparties' nonperformance. The Company only enters into agreements and material transactions with counterparties that have investment grade credit ratings by Moody's and S&P or with counterparties who have posted collateral to cover potential credit exposure. The Company has also established risk management policies and controls to determine and monitor the creditworthiness of counterparties in order to mitigate the Company's exposure to counterparty credit risk. Therefore, the Company does not anticipate a material adverse effect on the financial statements as a result of counterparty nonperformance.

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Gulf Power Company 2017 Annual Report

11. QUARTERLY FINANCIAL INFORMATION (UNAUDITED)
Summarized quarterly financial information for 2017 and 2016 is as follows:

| Quarter Ended | Operating Revenues | Operating Income | Net Income After Dividends on Preference Stock |
|---|---|---|---|
| | (in millions) | | |
| March 2017 | $350 | $ 46 | $ 18 |
| June 2017 | 357 | 75 | 35 |
| September 2017 | 437 | 115 | 63 |
| December 2017 | 372 | 53 | 19 |
| | | | |
| March 2016 | $335 | $ 65 | $ 29 |
| June 2016 | 365 | 74 | 34 |
| September 2016 | 436 | 90 | 45 |
| December 2016 | 349 | 54 | 23 |

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

SELECTED FINANCIAL AND OPERATING DATA 2013-2017
Gulf Power Company 2017 Annual Report

| | 2017 | 2016 | 2015 | 2014 | 2013 |
|---|---|---|---|---|---|
| Operating Revenues (in millions) | $ 1,516 | $ 1,485 | $ 1,483 | $ 1,590 | $ 1,440 |
| Net Income After Dividends on Preference Stock (in millions) | $ 135 | $ 131 | $ 148 | $ 140 | $ 124 |
| Cash Dividends on Common Stock (in millions) | $ 165 | $ 120 | $ 130 | $ 123 | $ 115 |
| Return on Average Common Equity (percent) | 9.22 | 9.52 | 11.11 | 11.02 | 10.30 |
| Total Assets (in millions)[(a)(b)] | $ 4,797 | $ 4,822 | $ 4,920 | $ 4,697 | $ 4,321 |
| Gross Property Additions (in millions) | $ 201 | $ 179 | $ 247 | $ 361 | $ 305 |
| Capitalization (in millions): | | | | | |
| Common stock equity | $ 1,531 | $ 1,389 | $ 1,355 | $ 1,309 | $ 1,235 |
| Preference stock | — | 147 | 147 | 147 | 147 |
| Long-term debt[(a)] | 1,285 | 987 | 1,193 | 1,362 | 1,150 |
| Total (excluding amounts due within one year) | $ 2,816 | $ 2,523 | $ 2,695 | $ 2,818 | $ 2,532 |
| Capitalization Ratios (percent): | | | | | |
| Common stock equity | 54.4 | 55.1 | 50.3 | 46.5 | 48.8 |
| Preference stock | — | 5.8 | 5.4 | 5.2 | 5.8 |
| Long-term debt[(a)] | 45.6 | 39.1 | 44.3 | 48.3 | 45.4 |
| Total (excluding amounts due within one year) | 100.0 | 100.0 | 100.0 | 100.0 | 100.0 |
| Customers (year-end): | | | | | |
| Residential | 404,273 | 398,501 | 393,149 | 388,292 | 383,980 |
| Commercial | 56,700 | 56,091 | 55,460 | 54,892 | 54,567 |
| Industrial | 255 | 254 | 248 | 260 | 260 |
| Other | 578 | 569 | 614 | 603 | 582 |
| Total | 461,806 | 455,415 | 449,471 | 444,047 | 439,389 |
| Employees (year-end) | 1,288 | 1,352 | 1,391 | 1,384 | 1,410 |

(a) A reclassification of debt issuance costs from Total Assets to Long-term debt of $8 million and $8 million is reflected for years 2014 and 2013, respectively, in accordance with new accounting standards adopted in 2015 and applied retrospectively.

(b) A reclassification of deferred tax assets from Total Assets of $3 million and $8 million is reflected for years 2014 and 2013, respectively, in accordance with new accounting standards adopted in 2015 and applied retrospectively.

SELECTED FINANCIAL AND OPERATING DATA 2013-2017 (continued)
Gulf Power Company 2017 Annual Report

| | 2017 | 2016 | 2015 | 2014 | 2013 |
|---|---|---|---|---|---|
| Operating Revenues (in millions): | | | | | |
| Residential | $720 | $714 | $698 | $700 | $632 |
| Commercial | 412 | 410 | 403 | 408 | 395 |
| Industrial | 144 | 152 | 144 | 153 | 139 |
| Other | 5 | 5 | 4 | 6 | 4 |
| Total retail | 1,281 | 1,281 | 1,249 | 1,267 | 1,170 |
| Wholesale — non-affiliates | 57 | 61 | 107 | 129 | 109 |
| Wholesale — affiliates | 108 | 75 | 58 | 130 | 100 |
| Total revenues from sales of electricity | 1,446 | 1,417 | 1,414 | 1,526 | 1,379 |
| Other revenues | 70 | 68 | 69 | 64 | 61 |
| Total | $1,516 | $1,485 | $1,483 | $1,590 | $1,440 |
| Kilowatt-Hour Sales (in millions): | | | | | |
| Residential | 5,229 | 5,358 | 5,365 | 5,362 | 5,089 |
| Commercial | 3,814 | 3,869 | 3,898 | 3,838 | 3,810 |
| Industrial | 1,740 | 1,830 | 1,798 | 1,849 | 1,700 |
| Other | 26 | 25 | 25 | 26 | 21 |
| Total retail | 10,809 | 11,082 | 11,086 | 11,075 | 10,620 |
| Wholesale — non-affiliates | 749 | 751 | 1,040 | 1,670 | 1,163 |
| Wholesale — affiliates | 3,887 | 2,784 | 1,906 | 3,284 | 3,127 |
| Total | 15,445 | 14,617 | 14,032 | 16,029 | 14,910 |
| Average Revenue Per Kilowatt-Hour (cents): | | | | | |
| Residential | 13.77 | 13.33 | 13.01 | 13.06 | 12.43 |
| Commercial | 10.80 | 10.60 | 10.34 | 10.64 | 10.37 |
| Industrial | 8.28 | 8.31 | 8.01 | 8.28 | 8.15 |
| Total retail | 11.85 | 11.56 | 11.27 | 11.44 | 11.02 |
| Wholesale | 3.56 | 3.85 | 5.60 | 5.23 | 4.87 |
| Total sales | 9.36 | 9.69 | 10.08 | 9.52 | 9.25 |
| Residential Average Annual Kilowatt-Hour Use Per Customer | 13,015 | 13,515 | 13,705 | 13,865 | 13,301 |
| Residential Average Annual Revenue Per Customer | $1,792 | $1,801 | $1,783 | $1,811 | $1,653 |
| Plant Nameplate Capacity Ratings (year-end) (megawatts) | 2,278 | 2,278 | 2,583 | 2,663 | 2,663 |
| Maximum Peak-Hour Demand (megawatts): | | | | | |
| Winter | 2,202 | 2,033 | 2,488 | 2,684 | 1,729 |
| Summer | 2,422 | 2,503 | 2,491 | 2,424 | 2,356 |
| Annual Load Factor (percent) | 55.2 | 54.7 | 54.9 | 51.1 | 55.9 |
| Plant Availability Fossil-Steam (percent) | 79.3 | 81.0 | 88.3 | 89.4 | 92.8 |
| Source of Energy Supply (percent): | | | | | |
| Coal | 33.1 | 31.0 | 33.5 | 44.5 | 36.4 |
| Gas | 27.8 | 23.2 | 25.6 | 22.2 | 23.0 |
| Purchased power — | | | | | |
| From non-affiliates | 35.6 | 41.1 | 30.4 | 28.9 | 37.0 |
| From affiliates | 3.5 | 4.7 | 10.5 | 4.4 | 3.6 |
| Total | 100.0 | 100.0 | 100.0 | 100.0 | 100.0 |

MISSISSIPPI POWER COMPANY
FINANCIAL SECTION

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MANAGEMENT'S REPORT ON INTERNAL CONTROL OVER FINANCIAL REPORTING
Mississippi Power Company 2017 Annual Report

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

Under management's supervision, an evaluation of the design and effectiveness of the Company's internal control over financial reporting was conducted based on the framework in Internal Control—Integrated Framework (2013) issued by the Committee of Sponsoring Organizations of the Treadway Commission. Based on this evaluation, management concluded that the Company's internal control over financial reporting was effective as of December 31, 2017.

/s/ Anthony L. Wilson
Anthony L. Wilson
Chairman, President, and Chief Executive Officer

/s/ Moses H. Feagin
Moses H. Feagin
Vice President, Chief Financial Officer, and Treasurer
February 20, 2018

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REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the stockholders and the Board of Directors of Mississippi Power Company

Opinion on the Financial Statements

We have audited the accompanying balance sheets and statements of capitalization of Mississippi Power Company (the Company) (a wholly-owned subsidiary of The Southern Company) as of December 31, 2017 and 2016, the related statements of operations, comprehensive income (loss), common stockholder's equity, and cash flows for each of the three years in the period ended December 31, 2017, and the related notes (collectively referred to as the "financial statements"). In our opinion, the financial statements (pages II-431 to II-477) 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.

Basis for Opinion

These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on the Company's financial statements 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 audit to obtain reasonable assurance about whether the financial statements are free of material misstatement, whether due to error or fraud. The Company is not required to have, nor were we engaged to perform, an audit of its internal control over financial reporting. As part of our audits, we are required to obtain an understanding of internal control over financial reporting but not for the purpose of expressing an opinion on the effectiveness of the Company's internal control over financial reporting. Accordingly, we express no such opinion. Our audits included performing procedures to assess the risks of material misstatement of the financial statements, whether due to error or fraud, and performing procedures that 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. We believe that our audits provide a reasonable basis for our opinion.

/s/ Deloitte & Touche LLP

Atlanta, Georgia

February 20, 2018

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

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DEFINITIONS

| Term | Meaning |
|---|---|
| 2012 MPSC CPCN Order | A detailed order issued by the Mississippi PSC in April 2012 confirming the CPCN originally approved by the Mississippi PSC in 2010 authorizing acquisition, construction, and operation of the Kemper County energy facility |
| AFUDC | Allowance for funds used during construction |
| Alabama Power | Alabama Power Company |
| ARO | Asset retirement obligation |
| ASC | Accounting Standards Codification |
| ASU | Accounting Standards Update |
| CCR | Coal combustion residuals |
| Clean Air Act | Clean Air Act Amendments of 1990 |
| $CO_2$ | Carbon dioxide |
| Cooperative Energy | Electric cooperative in Mississippi |
| CPCN | Certificate of public convenience and necessity |
| CWIP | Construction work in progress |
| DOE | U.S. Department of Energy |
| ECM | Energy cost management clause |
| ECO | Environmental compliance overview |
| EPA | U.S. Environmental Protection Agency |
| FASB | Financial Accounting Standards Board |
| FERC | Federal Energy Regulatory Commission |
| GAAP | U.S. generally accepted accounting principles |
| Georgia Power | Georgia Power Company |
| Gulf Power | Gulf Power Company |
| IGCC | Integrated coal gasification combined cycle, the technology originally approved for Mississippi Power's Kemper County energy facility (Plant Ratcliffe) |
| IRS | Internal Revenue Service |
| ITC | Investment tax credit |
| KWH | Kilowatt-hour |
| LIBOR | London Interbank Offered Rate |
| 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 |
| mmBtu | Million British thermal units |
| Moody's | Moody's Investors Service, Inc. |
| MPUS | Mississippi Public Utilities Staff |
| MRA | Municipal and Rural Associations |
| MW | Megawatt |
| $NO_X$ | Nitrogen oxide |
| OCI | Other comprehensive income |
| PEP | Performance evaluation plan |
| 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 |

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DEFINITIONS
(continued)

| Term | Meaning |
|---|---|
| PPA | Power purchase agreement |
| PSC | Public Service Commission |
| ROE | Return on equity |
| S&P | S&P Global Ratings, a division of S&P Global Inc. |
| scrubber | Flue gas desulfurization system |
| SCS | Southern Company Services, Inc. (the Southern Company system service company) |
| SEC | U.S. Securities and Exchange Commission |
| $SO_2$ | Sulfur dioxide |
| Southern Company | The Southern Company |
| Southern Company Gas | Southern Company Gas and its subsidiaries |
| Southern Company system | Southern Company, the traditional electric operating companies, Southern Power, Southern Company Gas (as of July 1, 2016), Southern Electric Generating Company, Southern Nuclear, SCS, Southern Linc, PowerSecure, Inc. (as of May 9, 2016), and other subsidiaries |
| Southern Linc | Southern Communications Services, Inc. |
| Southern Nuclear | Southern Nuclear Operating Company, Inc. |
| Southern Power | Southern Power Company and its subsidiaries |
| SRR | System Restoration Rider, a tariff for retail property damage reserve |
| 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 |
| traditional electric operating companies | Alabama Power, Georgia Power, Gulf Power, and Mississippi Power |

MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS
Mississippi Power Company 2017 Annual Report
OVERVIEW
Business Activities
Mississippi Power Company (the Company) operates as a vertically integrated utility providing electric service to retail customers within its traditional service territory located within the State of Mississippi and to wholesale customers in the Southeast.
Many factors affect the opportunities, challenges, and risks of the Company's business of providing electric service. These factors include the Company's ability to maintain and grow energy sales and to operate in a constructive regulatory environment that provides timely recovery of prudently-incurred costs. These costs include those related to reliability, fuel, and stringent environmental standards, as well as ongoing capital and operations and maintenance expenditures and restoration following major storms. Appropriately balancing required costs and capital expenditures with customer prices will continue to challenge the Company for the foreseeable future.
The 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 the Company 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, the Company 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, the Company 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, the Company 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 the Company, 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 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 the Company'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, the Company 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) the Company to file a reserve margin plan with the Mississippi PSC by August 2018.

During the third and fourth quarters of 2017, the Company 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

MANAGEMENT'S DISCUSSION AND ANALYSIS (continued)
Mississippi Power Company 2017 Annual Report

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. The Company 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, the Company 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.

For additional information, see FUTURE EARNINGS POTENTIAL – "Kemper County Energy Facility" and "Other Matters" herein.

The Company's financial statement presentation contemplates continuation of the Company as a going concern as a result of Southern Company's anticipated ongoing financial support of the Company. For additional information, see Note 6 to the financial statements under "Going Concern." In June 2017, Southern Company made equity contributions totaling $1.0 billion to the Company. The Company used a portion of the proceeds to (i) prepay $300 million of the outstanding principal amount under its $1.2 billion unsecured term loan; (ii) repay $591 million of the outstanding principal amount of promissory notes to Southern Company; and (iii) repay $10 million of the outstanding principal amount of bank loans.

As of December 31, 2017, the Company's current liabilities exceeded current assets by approximately $911 million primarily due to a $900 million unsecured term loan that matures on March 31, 2018. The Company expects to refinance the unsecured term loan with external security issuances and/or borrowings from financial institutions or Southern Company. To fund the Company's capital needs over the next 12 months, the Company intends to utilize operating cash flows, external security issuances, lines of credit, bank term loans, equity contributions from Southern Company, and, to the extent necessary, loans from Southern Company.

The Company continues to focus on several key performance indicators. In recognition that the Company's long-term financial success is dependent upon how well it satisfies its customers' needs, the Company's retail base rate mechanism, PEP, includes performance indicators that directly tie customer service indicators to the Company's allowed ROE. PEP measures the Company's performance on a 10-point scale as a weighted average of results in three areas: average customer price, as compared to prices of other regional utilities (weighted at 40%); service reliability, measured in percentage of time customers had electric service (40%); and customer satisfaction, measured in a survey of residential customers (20%). The Company also focuses on broader measures of customer satisfaction, plant availability, system reliability, and net income after dividends on preferred stock.

On January 16, 2018, the Mississippi PSC approved the 2018 retail fuel cost recovery factor, effective February 2018 through January 2019, which resulted in a $39 million increase in annual revenues. On February 7, 2018, the Company filed its 2018 PEP forecast, requesting an increase in annual base revenues of $26 million. On February 14, 2018, the Company submitted its 2018 ECO filing, requesting an increase in annual retail revenue of $17 million. The PEP and ECO filings include the effects of Tax Reform Legislation. Rulings from the Mississippi PSC on the PEP and ECO filings are expected in the first half of 2018. See FUTURE EARNINGS POTENTIAL – "Retail Regulatory Matters" herein and Note 3 to the financial statements under "Retail Regulatory Matters – Performance Evaluation Plan" for more information. The ultimate outcome of this matter cannot be determined at this time.

The Company's financial success is directly tied to customer satisfaction. Key elements of ensuring customer satisfaction include outstanding service, high reliability, and competitive prices. Management uses customer satisfaction surveys to evaluate the Company's results and generally targets top-quartile performance.

See RESULTS OF OPERATIONS herein for information on the Company's financial performance.

Earnings

The Company's net loss after dividends on preferred stock was $2.59 billion in 2017 compared to a $50 million net loss in 2016. The change in 2017 was primarily the result of higher pre-tax charges of $3.36 billion ($2.39 billion after tax) in 2017 compared to pre-tax charges of $428 million ($264 million after tax) in 2016 for estimated losses on the Kemper IGCC.

The Company's net loss after dividends on preferred stock was $50 million in 2016 compared to $8 million in 2015. The change in 2016 was primarily the result of higher pre-tax charges of $428 million ($264 million after tax) in 2016 compared to pre-tax charges of $365 million ($226 million after tax) in 2015 for estimated losses on the Kemper IGCC. The decrease in net income was partially offset by an increase in retail revenues due to the implementation of rates in September 2015 for certain Kemper

County energy facility in-service assets, partially offset by a decrease in wholesale revenues. The increase in revenues was partially offset by an increase in interest expense in 2016 compared to 2015 due to the termination of an asset purchase agreement between the Company and Cooperative Energy in 2015 and an increase in operations and maintenance expenses.

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

RESULTS OF OPERATIONS

A condensed statement of operations follows:

| | Amount | Increase (Decrease) from Prior Year | |
|---|---|---|---|
| | 2017 | 2017 | 2016 |
| | (in millions) | | |
| Operating revenues | $1,187 | $ 24 | $ 25 |
| Fuel | 395 | 52 | (100) |
| Purchased power | 25 | (9) | 22 |
| Other operations and maintenance | 282 | (30) | 38 |
| Depreciation and amortization | 161 | 29 | 9 |
| Taxes other than income taxes | 104 | (5) | 15 |
| Estimated loss on Kemper IGCC | 3,362 | 2,934 | 63 |
| Total operating expenses | 4,329 | 2,971 | 47 |
| Operating loss | (3,142) | (2,947) | (22) |
| Allowance for equity funds used during construction | 72 | (52) | 14 |
| Interest expense, net of amounts capitalized | 42 | (32) | 67 |
| Other income (expense), net | (8) | (1) | 1 |
| Income taxes (benefit) | (532) | (428) | (32) |
| Net income (loss) | (2,588) | (2,540) | (42) |
| Dividends on preferred stock | 2 | — | — |
| Net loss after dividends on preferred stock | $(2,590) | $ (2,540) | $ (42) |

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MANAGEMENT'S DISCUSSION AND ANALYSIS (continued)
Mississippi Power Company 2017 Annual Report

Operating Revenues
Operating revenues for 2017 were $1.2 billion, reflecting a $24 million increase from 2016. Details of operating revenues were as follows:

| | Amount | |
|---|---|---|
| | 2017 | 2016 |
| | (in millions) | |
| Retail — prior year | $859 | $776 |
| Estimated change resulting from — | | |
| Rates and pricing | (7) | 96 |
| Sales growth (decline) | 4 | (4) |
| Weather | (15) | 8 |
| Fuel and other cost recovery | 13 | (17) |
| Retail — current year | 854 | 859 |
| Wholesale revenues — | | |
| Non-affiliates | 259 | 261 |
| Affiliates | 56 | 26 |
| Total wholesale revenues | 315 | 287 |
| Other operating revenues | 18 | 17 |
| Total operating revenues | $1,187 | $1,163 |
| Percent change | 2.1 % | 2.2 % |

Total retail revenues for 2017 decreased $5 million, or 0.6%, compared to 2016 primarily due to a $15 million decrease as a result of milder weather in 2017 and the deferral of $17 million of revenue following the complete amortization of certain regulatory assets related to the Kemper County energy facility in July 2017. These decreases were partially offset by a $10 million net increase related to ECO plan rate changes in the third quarter 2016 and the second quarter 2017 and an increase of $13 million in fuel cost recovery. Total retail revenues for 2016 increased $83 million, or 10.7%, compared to 2015 primarily due to changes in rates and pricing of $96 million, partially offset by a net decrease in fuel and other cost recovery of $17 million.

See Note 3 to the financial statements under "Retail Regulatory Matters – Environmental Compliance Overview" and "Kemper County Energy Facility – Rate Recovery" for additional information. See "Energy Sales" below for a discussion of changes in the volume of energy sold, including changes related to sales and weather.

Electric rates for the Company include provisions to adjust billings for fluctuations in fuel costs, including the energy component of purchased power costs. Under these provisions, fuel revenues generally equal fuel expenses, including the energy component of purchased power costs, and do not affect net income. Recoverable fuel costs include fuel and purchased power expenses reduced by the fuel and emissions portion of wholesale revenues from energy sold to customers outside the Company's service territory. See FUTURE EARNINGS POTENTIAL – "Retail Regulatory Matters – Fuel Cost Recovery" herein for additional information.

Wholesale revenues from power sales to non-affiliated utilities, including FERC-regulated MRA sales as well as market-based sales, were as follows:

| | 2017 | 2016 | 2015 |
|---|---|---|---|
| | (in millions) | | |
| Capacity and other | $154 | $157 | $158 |
| Energy | 105 | 104 | 112 |
| Total non-affiliated | $259 | $261 | $270 |

Wholesale revenues from sales to non-affiliates will vary depending on fuel prices, the market prices of wholesale energy compared to the cost of the Company's and the Southern Company system's generation, demand for energy within the Southern Company system's electric service territory, and the availability of the Southern Company system's generation. Increases and decreases in energy revenues that are driven by fuel prices are accompanied by an increase or decrease in fuel costs and do not

MANAGEMENT'S DISCUSSION AND ANALYSIS (continued)
Mississippi Power Company 2017 Annual Report

have a significant impact on net income. In addition, the Company provides service under long-term contracts with rural electric cooperative associations and municipalities located in southeastern Mississippi under cost-based electric tariffs which are subject to regulation by the FERC. The contracts with these wholesale customers represented 19.3% of the Company's total operating revenues in 2017 and are largely subject to rolling 10-year cancellation notices. Historically, these wholesale customers have acted as a group and any changes in contractual relationships for one customer are likely to be followed by the other wholesale customers.
Short-term opportunity energy sales are also included in sales for resale to non-affiliates. These opportunity sales are made at market-based rates that generally provide a margin above the Company's variable cost to produce the energy.
Wholesale revenues from sales to affiliates will vary depending on demand and the availability and cost of generating resources at each company. These affiliate sales are made in accordance with the Intercompany Interchange Contract (IIC), as approved by the FERC. These transactions do not have a significant impact on earnings since this energy is generally sold at marginal cost.
Wholesale revenues from sales to affiliates increased $30 million, or 115.4%, in 2017 compared to 2016. The increase was primarily due to higher natural gas prices and higher KWH sales due to dispatch of the Company's lower cost generation resources to serve system territorial load. Wholesale revenues from sales to affiliates decreased $50 million, or 65.8%, in 2016 compared to 2015 primarily due to a $50 million decrease in energy revenues of which $4 million was associated with lower fuel prices and $46 million was associated with a decrease in KWH sales as a result of lower cost generation available in the Southern Company system.
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 2017 (in millions) | Total KWH Percent Change 2017 | 2016 | Weather-Adjusted Percent Change 2017 | 2016 |
|---|---|---|---|---|---|
| Residential | 1,944 | (5.2 )% | 1.3 % | 1.4 % | (2.4 )% |
| Commercial | 2,764 | (2.7 ) | 1.3 | (0.1 ) | (2.2 ) |
| Industrial | 4,841 | (1.3 ) | (1.0 ) | (1.3 ) | (1.6 ) |
| Other | 39 | (1.6 ) | (1.3 ) | (1.6 ) | (1.3 ) |
| Total retail | 9,588 | (2.5 ) | 0.1 | (0.4 )% | (1.9 )% |
| Wholesale | | | | | |
| Non-affiliated | 3,672 | (6.3 ) | 1.7 | | |
| Affiliated | 2,024 | 82.7 | (60.5) | | |
| Total wholesale | 5,696 | 14.0 | (24.5) | | |
| Total energy sales | 15,284 | 2.8 % | (9.8 )% | | |

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 2.5% in 2017 as compared to the prior year. This decrease was primarily the result of milder weather in 2017 as compared to 2016. Weather-adjusted residential KWH sales increased in 2017 primarily due to increased customer usage. Weather-adjusted commercial KWH sales decreased primarily due to decreased customer usage largely offset by customer growth. The decrease in industrial KWH energy sales was primarily due to Hurricane Nate, which impacted several large industrial customers.
Retail energy sales increased 0.1% in 2016 as compared to the prior year. This increase was primarily the result of warmer weather in the third quarter 2016 as compared to the corresponding period in 2015. Weather-adjusted residential and commercial KWH sales decreased primarily due to decreased customer usage partially offset by customer growth. The decrease in industrial KWH energy sales was primarily due to planned and unplanned outages by large industrial customers.

See "Operating Revenues" above for a discussion of significant changes in wholesale revenues to affiliated companies.

MANAGEMENT'S DISCUSSION AND ANALYSIS (continued)
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Fuel and Purchased Power Expenses
Fuel costs constitute one of the largest expenses for the Company. The mix of fuel sources for generation of electricity is determined primarily by demand, the unit cost of fuel consumed, and the availability of generating units. Additionally, the Company purchases a portion of its electricity needs from the wholesale market.
Details of the Company's generation and purchased power were as follows:

| | 2017 | 2016 | 2015 |
|---|---|---|---|
| Total generation (in millions of KWHs) | 15,319 | 14,514 | 17,014 |
| Total purchased power (in millions of KWHs) | 1,314 | 1,574 | 539 |
| Sources of generation (percent) – | | | |
| Gas | 92 | 91 | 83 |
| Coal | 8 | 9 | 17 |
| Cost of fuel, generated (in cents per net KWH) – | | | |
| Gas | 2.69 | 2.41 | 2.58 |
| Coal | 3.64 | 3.91 | 3.71 |
| Average cost of fuel, generated (in cents per net KWH) | 2.77 | 2.55 | 2.78 |
| Average cost of purchased power (in cents per net KWH) | 3.50 | 3.07 | 2.17 |

Fuel and purchased power expenses were $420 million in 2017, an increase of $43 million, or 11.4%, as compared to the prior year. The increase was primarily due to a $36 million increase in the average cost of generation and purchased power and a net increase of $7 million in KWHs generated from gas generation.
Fuel and purchased power expenses were $377 million in 2016, a decrease of $78 million, or 17.1%, as compared to the prior year. The decrease was primarily due to a decrease of $70 million in the volume of KWHs generated and purchased and an $8 million increase in the average cost of generation and purchased power.
Fuel and purchased power energy transactions do not have a significant impact on earnings, since energy expenses are generally offset by energy revenues through the Company's fuel cost recovery clauses. See FUTURE EARNINGS POTENTIAL – "Retail Regulatory Matters – Fuel Cost Recovery" herein and Note 1 to the financial statements under "Fuel Costs" for additional information.
Fuel
Fuel expense increased $52 million, or 15.2%, in 2017 compared to 2016 primarily due to an 11.6% higher cost of natural gas. Fuel expense decreased $100 million, or 22.6%, in 2016 compared to 2015 due to an 8.2% decrease in the average cost of fuel per KWH generated and a 15.5% decrease in the volume of KWHs generated.
Purchased Power
Purchased power expense decreased $9 million, or 26.5%, in 2017 compared to 2016. The decrease was primarily the result of a 16.5% decrease in the volume of KWHs purchased offset by a slight increase in the average cost per KWH purchased compared to 2016. Purchased power expense increased $22 million, or 183.3%, in 2016 compared to 2015. The increase in 2016 was primarily the result of a 192.1% increase in the volume of KWHs purchased due to the availability of lower cost energy as compared to the cost of self-generation.
Energy purchases will vary depending on the market prices of wholesale energy as compared to the cost of the Southern Company system's generation, demand for energy within the Southern Company system's service territory, and the availability of the Southern Company system's generation. These purchases are made in accordance with the IIC or other contractual agreements, as approved by the FERC.
Other Operations and Maintenance Expenses
Other operations and maintenance expenses decreased $30 million, or 9.6%, in 2017 compared to the prior year. The decrease was primarily due to a $10 million decrease in transmission and distribution expenses related to overhead line maintenance, an $8 million decrease in contractor services related to facilities, corporate advertising, and employee compensation and benefits, and an $8 million decrease related to the combined cycle and the associated common facilities portion of the Kemper County energy facility.

MANAGEMENT'S DISCUSSION AND ANALYSIS (continued)
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Other operations and maintenance expenses increased $38 million, or 13.9%, in 2016 compared to the prior year. The increase was primarily due to increases of $28 million related to the combined cycle and associated common facilities portion of the Kemper County energy facility and $10 million in amortization of prior expense deferrals, both following the In-Service Asset Rate Order in December 2015, as well as a $7 million increase in transmission and distribution expenses primarily related to overhead line maintenance and vegetation management expenses, partially offset by a $9 million decrease in planned generation outage costs.

Depreciation and Amortization

Depreciation and amortization increased $29 million, or 22.0%, in 2017 compared to 2016 primarily due to $13 million of amortization related to the ECO plan, $7 million of depreciation for additional plant in service, and $6 million in additional regulatory asset amortization associated with the Mercury and Air Toxics Standards (MATS) rule compliance.

Depreciation and amortization increased $9 million, or 7.3%, in 2016 compared to 2015 primarily due to $32 million of additional regulatory asset amortization related to the In-Service Asset Rate Order, ECO plan, and MATS rule compliance, $13 million associated with Kemper County energy facility deferrals primarily related to depreciation deferrals in 2015, and $9 million of depreciation for additional plant in service assets primarily associated with the Plant Daniel scrubbers. These increases were partially offset by $23 million of regulatory deferrals related to the In-Service Asset Rate Order and a $22 million deferral associated with the implementation of revised ECO plan rates with the first billing cycle for September 2016.

See Note 1 to the financial statements under "Depreciation and Amortization" and Note 3 to the financial statements under "FERC Matters" and "Retail Regulatory Matters – Environmental Compliance Overview Plan" for additional information.

Taxes Other Than Income Taxes

Taxes other than income taxes decreased $5 million, or 4.6%, in 2017 compared to 2016 primarily due to a decrease in franchise taxes of $4 million, as well as a decrease in ad valorem taxes of $1 million. Taxes other than income taxes increased $15 million, or 16.0%, in 2016 compared to 2015 primarily due to increases in ad valorem taxes of $10 million, related to an increase in the assessed value of property, as well as increases in franchise taxes of $5 million, related to increased operating revenue.

The retail portion of ad valorem taxes is recoverable under the Company's ad valorem tax cost recovery clause and, therefore, does not affect net income.

Estimated Loss on Kemper IGCC

In 2017, 2016, and 2015, estimated probable losses on the Kemper IGCC of $3.36 billion, $428 million, and $365 million, respectively, were recorded. On June 28, 2017, the Company 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, the Company 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 $52 million, or 41.9%, in 2017 as compared to 2016 as a result of the Kemper IGCC project suspension in June 2017. AFUDC equity increased $14 million, or 12.7%, in 2016 as compared to 2015 primarily due to a higher AFUDC rate and an increase in Kemper County energy facility CWIP subject to AFUDC prior to the suspension of the gasifier portion of the project, partially offset by placing the Plant Daniel scrubbers in service in November 2015. See ACCOUNTING POLICIES – "Application of Critical Accounting Policies and Estimates – Allowance for Funds Used During Construction" herein and Note 3 to the financial statements under "Kemper County Energy Facility" for additional information.

Interest Expense, Net of Amounts Capitalized

Interest expense, net of amounts capitalized decreased $32 million in 2017 compared to 2016. The decrease was primarily associated with a $36 million net reduction in interest following a settlement with the IRS related to research and experimental (R&E) deductions. Also contributing to the decrease was the amortization of $6 million in interest deferrals in accordance with the In-Service Asset Rate Order and a $7 million decrease in interest related to outstanding debt as a result of lower balances and lower rates. These decreases were partially offset by a $20 million reduction in interest capitalized following suspension of the Kemper County energy facility construction.
See Note 5 to the financial statements under "Section 174 Research and Experimental Deduction" for additional information.

MANAGEMENT'S DISCUSSION AND ANALYSIS (continued)
Mississippi Power Company 2017 Annual Report

Interest expense, net of amounts capitalized increased $67 million in 2016 compared to 2015. The increase was primarily due to an increase of $31 million of interest on deposits resulting from the 2015 reversal of interest associated with the termination of an asset purchase agreement between the Company and Cooperative Energy in May 2015; a $20 million increase due to additional long-term debt and a $30 million decrease in amounts capitalized primarily resulting from $17 million of capitalized interest and the amortization of $13 million in interest deferrals in accordance with the In-Service Asset Rate Order. These net increases were partially offset by a decrease of $16 million in interest accrued on the Mirror CWIP liability prior to refund in 2015.

Income Taxes (Benefit)

Income tax benefits increased $428 million, or 411.5%, in 2017 compared to 2016 primarily due to $809 million in tax benefits on the estimated probable losses on the Kemper IGCC, net of the non-deductible AFUDC equity portion and the related state valuation allowances, partially offset by $372 million resulting from Tax Reform Legislation. Tax Reform Legislation earnings impacts are primarily due to revaluing deferred tax assets related to the Kemper County energy facility. See FUTURE EARNINGS POTENTIAL – "Income Tax Matters" herein and Note 5 to the financial statements for additional information.

Income tax benefits increased $32 million, or 44.4%, in 2016 compared to 2015 primarily as a result of an increase in the estimated probable losses on the Kemper IGCC and an increase in AFUDC equity, which is non-taxable.

Effects of Inflation

The Company is subject to rate regulation that is generally based on the recovery of historical and projected costs. The effects of inflation can create an economic loss since the recovery of costs could be in dollars that have less purchasing power. Any adverse effect of inflation on the Company's results of operations has not been substantial in recent years.

FUTURE EARNINGS POTENTIAL

General

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

The results of operations for the past three years are not necessarily indicative of future earnings potential. The level of the Company's future earnings depends on numerous factors that affect the opportunities, challenges, and risks of the Company's business of providing electric service. These factors include the Company's ability to recover its prudently-incurred costs, in a timely manner during a time of increasing costs, and its ability to prevail against legal challenges associated with the Kemper County energy facility. Future earnings will be driven primarily by customer growth. Earnings will also depend upon maintaining and growing sales, considering, among other things, the adoption and/or penetration rates of increasingly energy-efficient technologies and increasing volumes of electronic commerce transactions, both of which could contribute to a net reduction in customer usage. Earnings are subject to a variety of other factors. These factors include weather, competition, developing new and maintaining existing energy contracts and associated load requirements with other utilities and other wholesale customers, energy conservation practiced by customers, the use of alternative energy sources by customers, the price of electricity, the price elasticity of demand, and the rate of economic growth or decline in the Company's service territory. Demand for electricity is primarily driven by the pace of economic growth that may be affected by changes in regional and global economic conditions, which may impact future earnings.

The Company's retail base rates are set under the PEP, a rate plan approved by the Mississippi PSC. Two filings are made for each calendar year: the PEP projected filing, which is typically filed prior to the beginning of the year based on a projected revenue requirement, and the PEP lookback filing, which is filed after the end of the year and allows for review of the actual return compared to the allowed return range. See "Retail Regulatory Matters" herein and Note 3 to the financial statements under "Retail Regulatory Matters – Performance Evaluation Plan" for more information.
On October 4, 2017, the Company 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 new agreements are not expected to have a material impact on the Company's earnings; however, the co-generation assets located at the refinery are expected to be accounted for as a sales-type lease in accordance with the new lease accounting rules that become effective in 2019. These assets are also subject to a security interest granted to Chevron. See

FINANCIAL CONDITION AND LIQUIDITY – "Credit Rating Risk" herein for additional information. The ultimate outcome of this matter cannot be determined at this time.

On December 22, 2017, 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.

The Company provides service under long-term contracts with rural electric cooperative associations and municipalities located in southeastern Mississippi under cost-based electric tariffs which are subject to regulation by the FERC. The contracts with these wholesale customers represented 19.3% of the Company's total operating revenues in 2017 and are largely subject to rolling 10-year cancellation notices. Historically, these wholesale customers have acted as a group and any changes in contractual relationships for one customer are likely to be followed by the other wholesale customers.

Environmental Matters

The Company'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 Company 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 Company's 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 or through long-term wholesale agreements. Further, increased costs that are recovered through regulated rates could contribute to reduced demand for electricity, which could negatively affect results of operations, cash flows, and financial condition. 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. See Note 3 to the financial statements under "Retail Regulatory Matters – Environmental Compliance Overview Plan" for additional information.

Through 2017, the Company has invested approximately $643 million in environmental capital retrofit projects to comply with environmental requirements, with annual totals of approximately $9 million, $17 million, and $94 million 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 Company's current compliance strategy estimates capital expenditures of $63 million from 2018 through 2022, with annual totals of approximately $14 million, $16 million, $17 million, $13 million, and $3 million 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 Company 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. No areas within the Company's service territory have been or are anticipated to be designated nonattainment under the 2015 ozone

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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 Company-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 Company has fossil fuel-fired generation 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 and Mississippi. The outcome of ongoing CSAPR litigation, to which the Company 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 the 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 and Mississippi) 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 Company. The EPA has not yet responded to the SIP revisions proposed by states where the Company's generating units are located.

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 Company's 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 and distribution 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.

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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.
Based on cost estimates for closure and monitoring of ash ponds pursuant to the CCR Rule, the Company recorded AROs for each CCR unit in 2015. As further analysis is performed and closure details are developed, the Company will continue to periodically update these cost estimates as necessary. In December 2016, the Mississippi PSC granted a CPCN to the Company authorizing certain projects associated with complying with the CCR Rule. Additionally in this order, the Mississippi PSC also authorized the Company to recover any costs associated with the CPCN, including future monitoring costs, through the ECO clause. 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 the Company's AROs as of December 31, 2017.
Environmental Remediation
The Company 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 Company may also incur substantial costs to clean up affected sites. The Company has authority from the Mississippi PSC to recover approved environmental compliance costs through established regulatory mechanisms. The Company recognizes a liability for environmental remediation costs only when it determines a loss is probable and reasonably estimable.
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.
The EPA's GHG reporting rule requires annual reporting of GHG emissions expressed in terms of metric tons of $CO_2$ equivalent emissions for a company's operational control of facilities. Based on ownership or financial control of facilities, the Company's 2016 GHG emissions were approximately 7 million metric tons of $CO_2$ equivalent. The preliminary estimate of the Company's 2017 GHG emissions on the same basis is approximately 8 million metric tons of $CO_2$ equivalent.
FERC Matters

Municipal and Rural Associations Tariff

The Company provides wholesale electric service to Cooperative Energy, East Mississippi Electric Power Association, and the City of Collins, all located in southeastern Mississippi, under a long-term cost-based, FERC regulated MRA tariff.

In March 2016, the Company reached a settlement agreement with its wholesale customers, which was subsequently approved by the FERC, for an increase in wholesale base revenues under the MRA cost-based electric tariff, primarily as a result of placing scrubbers for Plant Daniel Units 1 and 2 in service in 2015. The settlement agreement became effective for services rendered beginning May 1, 2016, resulting in an estimated annual revenue increase of $7 million under the MRA cost-based electric tariff. Additionally, under the settlement agreement, the tariff customers agreed to similar regulatory treatment for MRA tariff ratemaking as the treatment approved for retail ratemaking under the In-Service Asset Rate Order. This regulatory treatment primarily includes (i) recovery of the operational Kemper County energy facility assets providing service to customers and other related costs, (ii) amortization of the Kemper County energy facility-related regulatory assets included in rates under the settlement agreement over the 36 months ending April 30, 2019, (iii) Kemper County energy facility-related expenses included in rates under the settlement agreement no longer being deferred and charged to expense, and (iv) removing all of the Kemper County energy facility CWIP from rate base with a corresponding increase in accrual of AFUDC. The additional resulting AFUDC totaled approximately $22 million through the suspension of Kemper IGCC start-up activities and has been recorded as a charge to income.

The Company expects to make a subsequent MRA filing during the second quarter 2018. The filing is intended to be consistent with the February 6, 2018 Mississippi PSC order for cost recovery of the Kemper County energy facility, including the impact of Tax Reform Legislation. The ultimate outcome of this matter cannot be determined at this time.

On September 18, 2017, the Company and Cooperative Energy executed a Shared Service Agreement (SSA), as part of the MRA tariff, under which the Company and Cooperative Energy will share in providing electricity to all Cooperative Energy delivery points, in lieu of the current arrangement under which each delivery point is specifically assigned to either entity. The SSA accepted by the FERC on October 31, 2017 became effective on January 1, 2018 and may be cancelled by Cooperative Energy with 10 years notice after December 31, 2020. The SSA provides Cooperative Energy the option to decrease its use of the Company's generation services under the MRA tariff, subject to annual and cumulative caps and a one-year notice requirement. In the event Cooperative Energy elects to reduce these services, the related reduction in the Company's revenues is not expected to be significant through 2020.

Fuel Cost Recovery

The Company has a wholesale MRA and a Market Based (MB) fuel cost recovery factor. Effective with the first billing cycle for September 2016, fuel rates decreased $11 million annually for wholesale MRA customers and $1 million annually for wholesale MB customers. Effective January 1, 2018, the wholesale MRA fuel rate increased $11 million annually. At December 31, 2017, over-recovered wholesale MRA fuel costs were immaterial and at December 31, 2016 were approximately $13 million, which is included in over-recovered regulatory clause liabilities, current in the balance sheets.

The Company's operating revenues are adjusted for differences in actual recoverable fuel cost and amounts billed in accordance with the currently approved cost recovery rate. Accordingly, changes in the billing factor should have no significant effect on the Company's revenues or net income, but will affect cash flow.

Market-Based Rate Authority

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

In December 2016, the traditional electric operating companies (including the Company) and Southern Power filed an amendment to their market-based rate tariff that proposed certain changes to the energy auction, as well as several non-tariff changes. On February 2, 2017, the FERC issued an order accepting all such changes subject to an additional condition of cost-based price caps for certain sales outside of the energy auction, finding that all of these changes would provide adequate alternative mitigation for the traditional electric operating companies' (including the Company's) and Southern Power's potential to exert market power in certain areas served by the traditional electric operating companies (including the Company) and in some adjacent areas. On May 17, 2017, the FERC accepted the traditional electric operating companies' (including the Company's) 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.

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On October 25, 2017, the FERC issued an order in response to the traditional electric operating companies' (including the Company's) and Southern Power's June 29, 2017 triennial updated market power analysis. The FERC directed the traditional electric operating companies (including the Company) 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 (including the Company) 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.

Cooperative Energy Power Supply Agreement

In 2008, the Company entered into a 10-year Power Supply Agreement (PSA) with Cooperative Energy for approximately 152 MWs, which became effective in 2011. Following certain plant retirements, the PSA capacity was reduced to 86 MWs. On February 5, 2018, the Company and Cooperative Energy executed an amendment to extend the PSA through March 31, 2021, effective April 1, 2018, with increased total capacity of 286 MWs.

Cooperative Energy also has a 10-year Network Integration Transmission Service Agreement (NITSA) with SCS for transmission service to certain delivery points on the Company's transmission system that became effective in 2011. As a result of the PSA amendments, Cooperative Energy and SCS amended the terms of the NITSA on January 12, 2018 to provide for the purchase of incremental transmission capacity for service beginning April 1, 2018 through March 31, 2021. This NITSA amendment remains subject to acceptance by the FERC. The ultimate outcome of these matters cannot be determined at this time.

Retail Regulatory Matters

General

The Company's rates and charges for service to retail customers are subject to the regulatory oversight of the Mississippi PSC. The Company's rates are a combination of base rates and several separate cost recovery clauses for specific categories of costs. These separate cost recovery clauses address such items as fuel and purchased power, energy efficiency programs, ad valorem taxes, property damage, and the costs of compliance with environmental laws and regulations. Costs not addressed through one of the specific cost recovery clauses are expected to be recovered through the Company's base rates. See Note 3 to the financial statements under "Retail Regulatory Matters" and "Kemper County Energy Facility" for additional information.

In 2012, the Mississippi PSC issued an order for the purpose of investigating and reviewing, for informational purposes only, the ROE formulas used by the Company and all other regulated electric utilities in Mississippi. In 2013, the MPUS filed with the Mississippi PSC its report on the ROE formulas used by the Company and all other regulated electric utilities in Mississippi.

In 2014, the Mississippi PSC issued an order for the purpose of investigating and reviewing the adoption of a uniform formula rate plan for the Company and other regulated electric utilities in Mississippi.

On January 26, 2018, the Mississippi PSC issued an order directing utilities to file within 30 days information regarding the impact on rates resulting from Tax Reform Legislation. The Company's Kemper County energy facility rates, approved on February 6, 2018, include the effects of Tax Reform Legislation. The Company's 2018 ECO, revised 2018 PEP, and 2018 SRR rate filings, all submitted in February 2018, include the effects of Tax Reform Legislation and are subject to approval by the Mississippi PSC.

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

Performance Evaluation Plan

The Company's retail base rates are set under the PEP, a rate plan approved by the Mississippi PSC. Two filings are made for each calendar year: the PEP projected filing, which is typically filed prior to the beginning of the year based on a projected revenue requirement, and the PEP lookback filing, which is filed after the end of the year and allows for review of the actual revenue requirement compared to the projected filing.

In 2011, the Company submitted its annual PEP lookback filing for 2010, which recommended no surcharge or refund. Later in 2011, the MPUS disputed certain items in the 2010 PEP lookback filing. In 2012, the Mississippi PSC issued an order canceling the Company's PEP lookback filing for 2011. In 2013, the MPUS contested the Company's PEP lookback filing for 2012, which indicated a refund due to customers of $5 million. Unresolved matters related to the 2010 PEP lookback filing, which remain under review, also impact the 2012 PEP lookback filing.

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In 2013, the Mississippi PSC approved the projected PEP filing for 2013, which resulted in a rate increase of 1.9%, or $15 million, annually, effective March 19, 2013. The Company may be entitled to $3 million in additional revenues related to 2013 as a result of the late implementation of the 2013 PEP rate increase.

In 2014, 2015, 2016, and 2017, the Company submitted its annual PEP lookback filings for the prior years, which for 2013 and 2014 each indicated no surcharge or refund and for each of 2015 and 2016 indicated a $5 million surcharge. Additionally, in July 2016, in November 2016, and on November 15, 2017, the Company submitted its annual projected PEP filings for 2016, 2017, and 2018, respectively, which for 2016 and 2017 indicated no change in rates and for 2018 indicated a rate increase of 4%, or $38 million in annual revenues. The Mississippi PSC suspended each of these filings to allow more time for review.

On February 7, 2018, the Company revised its annual projected PEP filing for 2018 to reflect the impacts of 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%. See FUTURE EARNINGS POTENTIAL – "Income Tax Matters – Federal Tax Reform Legislation" herein and Note 5 to the financial statements for additional information. The ultimate outcome of these matters cannot be determined at this time.

Energy Efficiency

In 2013, the Mississippi PSC approved an energy efficiency and conservation rule requiring electric and gas utilities in Mississippi serving more than 25,000 customers to implement energy efficiency programs and standards. Quick Start Plans, which include a portfolio of energy efficiency programs that are intended to provide benefits to a majority of customers, were extended by an order issued by the Mississippi PSC in July 2016, until the time the Mississippi PSC approves a comprehensive portfolio plan program. The ultimate outcome of this matter cannot be determined at this time.

On July 6, 2017, the Mississippi PSC issued an order approving the Company's Energy Efficiency Cost Rider 2017 compliance filing, which increased annual retail revenues by approximately $2 million effective with the first billing cycle for August 2017.

On November 30, 2017, the Company submitted its Energy Efficiency Cost Rider 2018 compliance filing, which included a small decrease in annual retail revenues. The ultimate outcome of this matter cannot be determined at this time.

See Note 3 to the financial statements under "Retail Regulatory Matters" for additional information.

Environmental Compliance Overview Plan

In 2012, the Mississippi PSC approved the Company's request for a CPCN to construct scrubbers on Plant Daniel Units 1 and 2, which were placed in service in 2015. These units are jointly owned by the Company and Gulf Power, with 50% ownership each. In 2014, the Company entered into a settlement agreement with the Sierra Club under which, among other things, the Company agreed to retire, repower with natural gas, or convert to an alternative non-fossil fuel source Plant Sweatt Units 1 and 2 (80 MWs) no later than December 2018 (and the units were retired in July 2016). The Company also agreed that it would cease burning coal and other solid fuel at Plant Watson Units 4 and 5 (750 MWs) and begin operating those units solely on natural gas no later than April 2015 (which occurred in April 2015) and cease burning coal and other solid fuel at Plant Greene County Units 1 and 2 (200 MWs) no later than April 2016 (which occurred in February and March 2016, respectively) and begin operating those units solely on natural gas (which occurred in June and July 2016, respectively).

In accordance with a 2011 accounting order from the Mississippi PSC, the Company has the authority to defer in a regulatory asset for future recovery all plant retirement- or partial retirement-related costs resulting from environmental regulations. The Mississippi PSC approved $41 million and $17 million of costs that were reclassified to regulatory assets associated with Plant Watson and Plant Greene County, respectively, for amortization over five-year periods that began in July 2016 and July 2017, respectively. As a result, these decisions are not expected to have a material impact on the Company's financial statements.

In August 2016, the Mississippi PSC approved the Company's revised ECO plan filing for 2016, which requested the maximum 2% annual increase in revenues, or approximately $18 million, primarily related to the Plant Daniel Units 1 and 2 scrubbers placed in service in 2015. The revised rates became effective with the first billing cycle for September 2016. Approximately $22 million of related revenue requirements in excess of the 2% maximum was deferred for inclusion in the 2017 filing, along with related carrying costs.

On May 4, 2017, the Mississippi PSC approved the Company's ECO plan filing for 2017, which requested the maximum 2% annual increase in revenues, or approximately $18 million, primarily related to the carryforward from the prior year. The rates became effective with the first billing cycle for June 2017. Approximately $26 million of related revenue requirements in excess of the 2% maximum was deferred for inclusion in the 2018 filing, along with related carrying costs.

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On February 14, 2018, the Company submitted its ECO plan filing for 2018, including the effects of Tax Reform Legislation, which requested the maximum 2% annual increase in revenues, or approximately $17 million, primarily related to the carryforward from the prior year. Approximately $13 million of related revenue requirements in excess of the 2% maximum, along with related carrying costs, remains deferred for inclusion in the 2019 filing. The ultimate outcome of this matter cannot be determined at this time.

Fuel Cost Recovery

The Company establishes, annually, a retail fuel cost recovery factor that is approved by the Mississippi PSC. The Company is required to file for an adjustment to the retail fuel cost recovery factor annually. On January 12, 2017, the Mississippi PSC approved the 2017 retail fuel cost recovery factor, effective February 2017 through January 2018, which resulted in an annual revenue increase of approximately $55 million. On November 15, 2017, the Company filed its annual rate adjustment under the retail fuel cost recovery clause, requesting an additional increase of $39 million annually, which the Mississippi PSC approved on January 16, 2018 effective February 2018 through January 2019. At December 31, 2017, the amount of under-recovered retail fuel costs included in the balance sheet in customer accounts receivable was approximately $6 million compared to $37 million over recovered at December 31, 2016.

The Company's operating revenues are adjusted for differences in actual recoverable fuel cost and amounts billed in accordance with the currently approved cost recovery rate. Accordingly, changes in the billing factor should have no significant effect on the Company's revenues or net income, but will affect cash flow.

Ad Valorem Tax Adjustment

The Company establishes, annually, an ad valorem tax adjustment factor that is approved by the Mississippi PSC to collect the ad valorem taxes paid by the Company. On July 6, 2017, the Mississippi PSC approved the Company's annual ad valorem tax adjustment factor filing for 2017, which included an annual rate increase of 0.85%, or $8 million in annual retail revenues, primarily due to increased assessments.

System Restoration Rider

In February 2016, the Company submitted its 2016 SRR rate filing which proposed no changes to either the SRR rate or the annual property damage reserve accrual of $3 million annually. On February 3, 2017, the Company submitted its 2017 SRR rate filing, which proposed an increase in the property damage reserve accrual of $1 million. These filings were suspended by the Mississippi PSC for review.

On January 21, 2017, a tornado caused extensive damage to the Company's transmission and distribution infrastructure. Storm damage repairs were approximately $9 million. A portion of these costs was charged to the retail property damage reserve and was addressed in the 2018 SRR rate filing.

On February 1, 2018, the Company submitted its 2018 SRR rate filing, including the effects of Tax Reform Legislation, which proposed that the SRR rate remain at zero and the annual accrual for the property damage reserve be reduced to $2 million in 2018.

The ultimate outcome of these matters cannot be determined at this time. See Note 1 to the financial statements under "Provision for Property Damage" for additional information.

Storm Damage Cost Recovery

In connection with the damage associated with Hurricane Katrina, the Mississippi PSC authorized the issuance of system restoration bonds in 2006. In accordance with a Mississippi PSC order on January 24, 2017, the Company eliminated the applicable Storm Restoration Charge because the bond sinking fund managed by the Mississippi State Bond Commission is substantially funded.

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 the Company 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, the Company constructed approximately 61 miles of $CO_2$ pipeline infrastructure for the transport of captured $CO_2$ for use in enhanced oil recovery.

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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 in 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. The Company 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." The Company 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, the Company 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, the Company 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 the Company 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. On June 28, 2017, the Company 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 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 DOE Grants. In the aggregate, the Company 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, the Company 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, the Company 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. The Company 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 the Company'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, the Company made the required compliance filing with the Mississippi PSC. The Kemper

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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) the Company 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 the Company's actual average capital structure, with a maximum common equity percentage of 49.733%, a 9.225% return on common equity, and actual embedded interest costs. The In-Service Asset Rate Order also included a prudence finding of all costs in the stipulated revenue requirement calculation for the in-service assets.

In connection with the implementation of the In-Service Asset Rate Order and wholesale rates, the Company 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 the Company 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. See "FERC Matters" herein for additional information related to the 2016 settlement agreement with wholesale customers.

Lignite Mine and $CO_2$ Pipeline Facilities

The Company 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, the Company executed a 40-year management fee contract with Liberty Fuels Company, LLC (Liberty Fuels), a wholly-owned subsidiary of The North American Coal Corporation, which developed, constructed, and is 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 the Company has a contractual obligation to fund all reclamation activities. The Company expects mine reclamation to begin in 2018. In addition to the obligation to fund the reclamation activities, the Company provided working capital support to Liberty Fuels through cash advances for capital purchases, payroll, and other operating expenses. See Note 1 to the financial statements under "Asset Retirement Obligations and Other Costs of Removal" and "Variable Interest Entities" for additional information.

In addition, the Company 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 the Company 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 the Company was filed in Harrison County Circuit Court (Circuit Court) by Biloxi Freezing & Processing Inc., Gulfside Casino Partnership, and John Carlton Dean, which was amended and refiled on July 11, 2016 to include, among other things, Southern Company as a defendant. The individual plaintiff alleges that the Company and Southern Company violated the Mississippi Unfair Trade Practices Act. All plaintiffs have alleged that the Company and Southern Company concealed, falsely represented, and failed to fully disclose important facts concerning the cost and schedule of the Kemper County energy facility and that these alleged breaches have unjustly enriched the Company and Southern Company. The plaintiffs seek unspecified actual damages and punitive damages; ask the Circuit Court to appoint a receiver to oversee, operate, manage, and otherwise control all affairs relating to the Kemper County energy facility; ask the Circuit Court to revoke any licenses or certificates authorizing the Company or Southern Company to engage in any business related to the Kemper 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 the Company and dismissed the case. On July 7, 2017, the plaintiffs filed notice of an appeal. The Company believes this legal challenge has no merit; however, an adverse outcome in this proceeding

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could have a material impact on the Company's results of operations, financial condition, and liquidity. The 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 the Company, 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 the Company, Southern Company, and SCS and sought compensatory damages of $100 million, as well as unspecified punitive damages. Southern Company, the Company, 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, the Company reached a settlement agreement with Treetop, Greenleaf, Tenrgys, LLC, Tellus Energy, LLC, WCOA, LLC, and Tellus Operating Group and the arbitration was dismissed.

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

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.

Regulated utility businesses 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, net operating losses (NOL) 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 in the subsequent tax year.

For the year ended December 31, 2017, implementation of the Tax Reform Legislation resulted in an estimated net tax expense of $372 million and a $375 million increase in regulatory liabilities as of December 31, 2017, primarily due to the impact of the reduction of the corporate income tax rate on deferred tax assets and liabilities.

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 the Mississippi PSC. On January 31, 2018, SCS, on behalf of the traditional electric operating companies (including the Company), filed with the FERC a reduction to the Company's open access transmission tariff charge for 2018 to reflect the revised federal corporate tax rate. See Note 3 to the financial statements under "Regulatory Matters" for additional information regarding the Company's rate filings to reflect the impacts of the Tax Reform Legislation.

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, approximately $50 million of positive cash flows is expected to result from bonus depreciation for the 2017 tax year and approximately

$10 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," respectively, for additional information. The ultimate outcome of these matters cannot be determined at this time.

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Section 174 Research and Experimental Deduction
Southern Company, on behalf of the 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 (JCT), resolving a methodology for these deductions. As a result of this approval, the Company recognized $176 million of previously unrecognized tax benefits and reversed $36 million of associated accrued interest.
Other Matters
The Company is involved in various other matters being litigated and regulatory matters that could affect future earnings. In addition, the Company is subject to certain claims and legal actions arising in the ordinary course of business. The Company's business activities are subject to extensive governmental regulation related to public health and the environment, such as regulation of air emissions and water discharges. Litigation over environmental issues and claims of various types, including property damage, personal injury, common law nuisance, and citizen enforcement of environmental requirements, such as 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 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 the Company's financial statements. See Note 3 to the financial statements for a discussion of various other contingencies, regulatory matters, and other matters being litigated which may affect future earnings potential.
In 2013, the Company submitted a claim under the Deep Horizon Economic and Property Damages Settlement Agreement associated with the oil spill that occurred in the Gulf of Mexico. The ultimate outcome of this matter cannot be determined at this time.
In 2016, the SEC began conducting a formal investigation of Southern Company and the Company 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.
ACCOUNTING POLICIES
Application of Critical Accounting Policies and Estimates
The Company prepares its financial statements in accordance with GAAP. Significant accounting policies are described in Note 1 to the financial statements. In the application of these policies, certain estimates are made that may have a material impact on the Company's results of operations and related disclosures. Different assumptions and measurements could produce estimates that are significantly different from those recorded in the financial statements. Senior management has reviewed and discussed the following critical accounting policies and estimates with the Audit Committee of Southern Company's Board of Directors.
Utility Regulation
The Company is subject to retail regulation by the Mississippi PSC and wholesale regulation by the FERC. These regulatory agencies set the rates the Company is permitted to charge customers based on allowable costs. As a result, the Company applies accounting standards which require the financial statements to reflect the effects of rate regulation. Through the ratemaking process, the regulators may require the inclusion of costs or revenues in periods different than when they would be recognized by a non-regulated company. This treatment may result in the deferral of expenses and the recording of related regulatory assets based on anticipated future recovery through rates or the deferral of gains or creation of liabilities and the recording of related regulatory liabilities. The application of the accounting standards has a further effect on the Company's financial statements as a result of the estimates of allowable costs used in the ratemaking process. These estimates may differ from those actually incurred by the

Company; therefore, the accounting estimates inherent in specific costs such as depreciation and pension and other postretirement benefits have less of a direct impact on the Company's results of operations and financial condition than they would on a non-regulated company.

As reflected in Note 1 to the financial statements, significant regulatory assets and liabilities have been recorded. Management reviews the ultimate recoverability of these regulatory assets and any requirement to refund these regulatory liabilities based on

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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. The Company 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 the Company 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 the Company'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, the Company 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, the Company 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, the Company has incurred charges of $6.20 billion ($4.14 billion after tax) through December 31, 2017. See Note 11 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.

Federal Tax Reform Legislation

Following the enactment of 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, the Company considers all amounts recorded in the financial statements as a result of Tax Reform Legislation to be "provisional" as discussed in SAB 118 and subject to revision. The Company is awaiting additional guidance from industry and income tax authorities in order to finalize its accounting. The ultimate impact of 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 "Retail Regulatory Matters – Rate Plans" 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. In addition, the Company has retirement obligations related to various landfill sites, underground storage tanks, deep injection wells, water wells, substation removal, mine reclamation, and asbestos removal. The Company also has identified retirement obligations related to certain transmission and distribution facilities and certain wireless communication towers. However, liabilities for the removal of these assets have not been recorded because the settlement timing for the retirement obligations related to these assets is indeterminable and, therefore, the fair value of the retirement obligations cannot be reasonably estimated. A liability for these AROs will be recognized when sufficient information becomes available to support a reasonable estimation of the ARO.

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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 Company 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" for additional information.

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

Pension and Other Postretirement Benefits

The Company's calculation of pension and other postretirement benefits expense is dependent on a number of assumptions. These assumptions include discount rates, healthcare cost trend rates, expected long-term return on plan assets, mortality rates, expected salary and wage increases, and other factors. Components of pension and other postretirement benefits expense include interest and service cost on the pension and other postretirement benefit plans, expected return on plan assets, and amortization of certain unrecognized costs and obligations. Actual results that differ from the assumptions utilized are accumulated and amortized over future periods and, therefore, generally affect recognized expense and the recorded obligation in future periods. While the Company believes that the assumptions used are appropriate, differences in actual experience or significant changes in assumptions would affect its pension and other postretirement benefits costs and obligations.

Key elements in determining the Company's pension and other postretirement benefit expense are the expected long-term return on plan assets and the discount rate used to measure the benefit plan obligations and the periodic benefit plan expense for future periods. The expected long-term return on pension and other postretirement benefit plan assets is based on the Company's investment strategy, historical experience, and expectations for long-term rates of return that consider external actuarial advice. The Company determines the long-term return on plan assets by applying the long-term rate of expected returns on various asset classes to the Company's target asset allocation. For purposes of determining its liability related to the pension and other postretirement benefit plans, the Company discounts the future related cash flows using a single-point discount rate developed from the weighted average of market-observed yields for high quality fixed income securities with maturities that correspond to expected benefit payments. For 2015 and prior years, the Company computed the interest cost component of its net periodic pension and other postretirement benefit plan expense using the same single-point discount rate. Beginning in 2016, the Company adopted a full yield curve approach for calculating the interest cost component whereby the discount rate for each year is applied to the liability for that specific year. As a result, the interest cost component of net periodic pension and other postretirement benefit plan expense decreased by approximately $4 million in 2016.

A 25 basis point change in any significant assumption (discount rate, salaries, or long-term return on plan assets) would result in a $2 million or less change in total annual benefit expense and a $25 million or less change in projected obligations.

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

Allowance for Funds Used During Construction

In accordance with regulatory treatment, the Company records AFUDC, which represents the estimated debt and equity costs of capital funds that are necessary to finance the construction of new regulated facilities. While cash is not realized currently from such allowance, AFUDC increases the revenue requirement over the service life of the plant through a higher rate base and higher depreciation. The equity component of AFUDC is not included in the calculation of taxable income. The average annual AFUDC rate was 6.7%, 6.5%, and 5.99% for the years ended December 31, 2017, 2016, and 2015, respectively. The AFUDC rate is applied to CWIP consistent with jurisdictional regulatory treatment. AFUDC equity was $72 million, $124 million, and $110 million in 2017, 2016, and 2015, respectively. The decrease in 2017 resulted from the Kemper County energy facility project suspension in June 2017.

Unbilled Revenues

Revenues related to the retail sale of electricity are recorded when electricity is delivered to customers. However, the determination of KWH sales to individual customers is based on the reading of their meters, which is performed on a systematic basis throughout the month. At the end of each month, amounts of electricity delivered to customers, but not yet metered and billed, are estimated. Components of the unbilled revenue estimates include total KWH territorial supply, total KWH billed, estimated total electricity lost in delivery, and customer usage. These components can fluctuate as a result of a number of factors including weather, generation patterns, power delivery volume, and other operational constraints. These factors can be unpredictable and can vary from historical trends. As a result, the overall estimate of unbilled revenues could be significantly affected, which could have a material impact on the Company's results of operations.

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Contingent Obligations
The Company is subject to a number of federal and state laws and regulations as well as other factors and conditions that subject it to environmental, litigation, income tax, and other risks. See FUTURE EARNINGS POTENTIAL herein and Note 3 to the financial statements for more information regarding certain of these contingencies. The Company periodically evaluates its exposure to such risks and records reserves for those matters where a non-tax-related loss is considered probable and reasonably estimable and records a tax asset or liability if it is more likely than not that a tax position will be sustained. The adequacy of reserves can be significantly affected by external events or conditions that can be unpredictable; thus, the ultimate outcome of such matters could materially affect the Company's results of operations, cash flows, or financial condition.
Recently Issued Accounting Standards
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 the Company's revenue, including energy provided to customers, is from tariff offerings that provide electricity without a defined contractual term, as well as longer-term contractual commitments, including PPAs.
The 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 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 the Company's financial statements, if material. The 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. The Company applied the modified retrospective method of adoption effective January 1, 2018. The 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. ASU 2016-02 is effective for fiscal years beginning after December 15, 2018 and the Company will adopt the new standard effective January 1, 2019.
The 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, the 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 equipment and cellular towers where the Company is the lessee and to equipment where the Company is the lessor. The Company is currently analyzing pole attachment agreements and a lease determination has not been made at this time. While the Company has not yet determined the

ultimate impact, adoption of ASU 2016-02 is expected to have a significant impact on the Company's balance sheet.

Other

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

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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 the 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. The 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. The Company adopted ASU 2017-12 effective January 1, 2018 with no material impact on its financial statements.

FINANCIAL CONDITION AND LIQUIDITY

Overview and Sources of Capital

Earnings for all periods presented were negatively affected by charges associated with the Kemper IGCC. See FUTURE EARNINGS POTENTIAL – "Kemper County Energy Facility" herein and Note 3 to the financial statements for additional information.

The Company's cash requirements primarily consist of funding ongoing operations, capital expenditures, and debt maturities. Capital expenditures and other investing activities include investments to maintain existing generation facilities, to comply with environmental regulations including adding environmental modifications to certain existing generating units, to expand and improve transmission and distribution facilities, and for restoration following major storms.

The Company's financial statement presentation contemplates continuation of the Company as a going concern as a result of Southern Company's anticipated ongoing financial support of the Company. Specifically, the Company has been informed by Southern Company that in the event sufficient funds are not available from external sources, Southern Company intends to provide the Company with loans and/or equity contributions sufficient to fund the remaining indebtedness scheduled to mature and other cash needs over the next 12 months. For additional information, see Note 6 to the financial statements under "Going Concern."

On February 28, 2017, the maturity dates for $551 million in promissory notes to Southern Company were extended to July 31, 2018. In the second quarter 2017, the Company borrowed an additional $40 million under a promissory note issued to Southern Company. In June 2017, Southern Company made equity contributions totaling $1.0 billion to the Company. The Company used a portion of the proceeds to (i) prepay $300 million of the outstanding principal amount under its $1.2 billion unsecured term loan; (ii) repay all of the $591 million outstanding principal amount of promissory notes to Southern Company; and (iii) repay $10 million of the outstanding principal amount of bank loans. In September 2017, the Company issued a floating rate promissory note to Southern Company in an aggregate principal amount of up to $150 million bearing interest based on one-month LIBOR. The Company borrowed $109 million under this promissory note primarily to satisfy its federal income tax obligations for the quarter ended September 30, 2017 and subsequently repaid the promissory note upon receipt of its income tax refund from the U.S. government related to the settlement concerning deductible R&E expenditures. See Note 5 to the financial statements under "Section 174 Research and Experimental Deduction" for additional information.

As of December 31, 2017, the Company's current liabilities exceeded current assets by approximately $911 million primarily due to a $900 million unsecured term loan that matures on March 31, 2018. The Company expects to refinance the unsecured term loan with external security issuances and/or borrowings from financial institutions or Southern Company. To fund the Company's capital needs over the next 12 months, the Company intends to utilize operating cash flows, external security issuances, lines of credit, bank term loans, equity contributions from Southern Company, and, to the extent necessary, loans from Southern Company.

The Company's capital expenditures and debt maturities are expected to materially exceed operating cash flows through 2022. The Company plans to obtain the funds required for construction and other purposes from operating cash flows, lines of credit,

MANAGEMENT'S DISCUSSION AND ANALYSIS (continued)
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bank term loans, external security issuances, commercial paper, to the extent the Company is eligible to participate, and loans and/or equity contributions from Southern Company.

The Company's investments in the qualified pension plan 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 plan are anticipated during 2018.

Net cash provided from operating activities totaled $503 million for 2017, an increase of $274 million as compared to 2016. The increase in cash provided from operating activities in 2017 was primarily due to tax refunds associated with the approval by the JCT of the Section 174 R&E settlement, largely offset by a decrease in income taxes related to the Kemper County energy facility and Tax Reform Legislation. Net cash provided from operating activities totaled $229 million for 2016, an increase of $56 million as compared to 2015. The increase in cash provided from operating activities in 2016 was primarily due to repayment in 2015 of ITCs relating to the Kemper County energy facility, as well as the 2015 mirror CWIP refund, partially offset by lower income tax benefits related to the Kemper County energy facility in 2016 and lower fuel rates in 2016.

Net cash used for investing activities in 2017, 2016, and 2015 totaled $504 million, $697 million, and $906 million, respectively. The cash used for investing activities in all years presented was primarily due to gross property additions related to the Kemper County energy facility. The cash used for investing activities in 2016 was partially offset by the receipt of Additional DOE Grants. The cash used for investing activities in 2015 also included gross property additions related to the Plant Daniel scrubber project.

Net cash provided from financing activities totaled $25 million in 2017 primarily due to capital contributions from Southern Company, largely offset by redemptions of long-term debt and short-term borrowings. Net cash provided from financing activities totaled $594 million in 2016 primarily due to long-term debt financings and capital contributions from Southern Company, partially offset by a decrease in short-term borrowings and redemptions of long-term debt. Net cash provided from financing activities totaled $698 million in 2015 primarily due to short-term borrowings, capital contributions from Southern Company, and long-term debt financings, partially offset by redemptions of long-term debt.

Significant balance sheet changes as of December 31, 2017 compared to 2016 include decreases of $2.5 billion in CWIP, a net change of $1.0 billion in accumulated deferred income taxes, an increase in paid-in capital of $1.0 billion due to capital contributions from Southern Company, a portion of which was used to repay $300 million of securities due within one year, $591 million of long-term debt, and $10 million of short-term debt. Long-term debt decreased primarily due to the reclassification of $1.2 billion in unsecured term loans to securities due within one year – other. Securities due within one year – parent decreased $551 million due to the repayment of promissory notes to Southern Company. Other significant balance sheet changes include $326 million in deferred charges related to income taxes. All of these changes primarily resulted from the Kemper IGCC suspension and related estimated loss. Income taxes receivable and unrecognized tax benefits also decreased due to tax refunds associated with the approval by the JCT of the Section 174 R&E settlement. The Company also had an increase of $365 million in deferred credits related to income taxes primarily resulting from the impacts of Tax Reform Legislation. See FUTURE EARNINGS POTENTIAL – "Kemper County Energy Facility" and "Income Tax Matters – Federal Tax Reform Legislation" herein and Notes 3 and 5 to the financial statements under "Kemper County Energy Facility" and "Section 174 Research and Experimental Deduction," respectively, for additional information.

The Company's ratio of common equity to total capitalization plus short-term debt was 39% and 49% at December 31, 2017 and 2016, respectively. The decrease was due to Kemper IGCC losses. See Note 6 to the financial statements for additional information.

The issuance of securities by the Company is subject to regulatory approval by the FERC. Additionally, with respect to the public offering of securities, the Company files registration statements with the SEC under the Securities Act of 1933, as amended. The amounts of securities authorized by the FERC are continuously monitored and appropriate filings are made to ensure flexibility in raising capital. Any future financing through secured debt would also require

approval by the Mississippi PSC.
The Southern Company system does not maintain a centralized cash or money pool. Therefore, funds of the Company are not commingled with funds of any other company in the Southern Company system.
At December 31, 2017, the Company had approximately $248 million of cash and cash equivalents. Committed credit arrangements with banks at December 31, 2017 were $100 million, all of which is unused. In November 2017, the Company amended its one-year credit arrangements in an aggregate amount of $100 million to extend the maturity dates from 2017 to 2018.
A portion of the $100 million unused credit arrangements with banks is allocated to provide liquidity support to the Company's revenue bonds. The amount of variable rate revenue bonds outstanding requiring liquidity support as of December 31, 2017 was approximately $40 million. In addition, the Company had approximately $50 million of fixed rate revenue bonds that were remarketed from a long-term interest rate mode to an index rate mode subsequent to December 31, 2017.

MANAGEMENT'S DISCUSSION AND ANALYSIS (continued)
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Most of these bank credit arrangements, as well as the Company's term loan agreement, contain covenants that limit debt levels and typically contain cross acceleration to other indebtedness (including guarantee obligations) of the Company. Such cross-acceleration provisions to other indebtedness would trigger an event of default if the Company defaulted on indebtedness, the payment of which was then accelerated. At December 31, 2017, the Company was in compliance with all such covenants. None of the bank credit arrangements contain material adverse change clauses at the time of borrowing.

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

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

Short-term borrowings are included in notes payable in the balance sheets. Details of short-term borrowing were as follows:

| | Short-term Debt at the End of the Period | | Short-term Debt During the Period (*) | | |
|---|---|---|---|---|---|
| | Amount Outstanding | Weighted Average Interest Rate | Average Outstanding | Weighted Average Interest Rate | Maximum Amount Outstanding |
| | (in millions) | | (in millions) | | (in millions) |
| December 31, 2017 | $4 | 3.8 % | $18 | 3.0 % | $ 36 |
| December 31, 2016 | $23 | 2.6 % | $112 | 2.0 % | $ 500 |
| December 31, 2015 | $500 | 1.4 % | $372 | 1.3 % | $ 515 |

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

Financing Activities

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

Bank Term Loans and Senior Notes

In March 2017, the Company issued a $9 million short-term bank note bearing interest at 5% per annum, which was repaid in April 2017.

In June 2017, the Company used a portion of the proceeds from Southern Company equity contributions to prepay $300 million of the outstanding principal amount under its $1.2 billion unsecured term loan, which matures on March 30, 2018, and to repay $10 million of the outstanding principal amount of bank loans. See "Parent Company Loans and Equity Contributions" herein for more information.

This unsecured term loan has covenants that limit debt levels to 65% of total capitalization, as defined in the agreement. For purposes of this definition, debt excludes the long-term debt payable to affiliated trusts and other hybrid securities. In addition, this unsecured term loan contains cross-acceleration provisions to other debt (including guarantee obligations) that would be triggered if the Company defaulted on debt above a specified threshold, the payment of which was then accelerated. The Company is currently in compliance with all such covenants.

In August 2017, the Company repaid a $12.5 million short-term bank note.

In November 2017, the Company repaid at maturity $35 million aggregate principal amount of Series 2007A 5.60% Senior Notes.

Parent Company Loans and Equity Contributions

In February 2017, the Company amended $551 million in promissory notes to Southern Company extending the maturity dates of the notes from December 1, 2017 to July 31, 2018. In the second quarter 2017, the Company borrowed an additional $40 million under a promissory note issued to Southern Company.
In June 2017, Southern Company made equity contributions totaling $1.0 billion to the Company. The Company used a portion of the proceeds to (i) prepay $300 million of the outstanding principal amount under its $1.2 billion unsecured term loan, which matures on March 30, 2018; (ii) repay all of the $591 million outstanding principal amount of promissory notes to Southern Company; and (iii) repay a $10 million short-term bank loan.

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In September 2017, the Company issued a floating rate promissory note to Southern Company in an aggregate principal amount of up to $150 million bearing interest based on one-month LIBOR. The Company borrowed $109 million under this promissory note primarily to satisfy its federal income tax obligations for the quarter ending September 30, 2017 and subsequently repaid the promissory note upon receipt of its income tax refund from the U.S. federal government related to the settlement concerning deductible R&E expenditures. See Note 5 to the financial statements under "Section 174 Research and Experimental Deduction" for additional information.

Credit Rating Risk

At December 31, 2017, 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.

On October 4, 2017, the Company executed agreements with its largest retail customer, Chevron, to continue providing retail service to the Chevron refinery in Pascagoula, Mississippi through 2038. The agreements grant Chevron a security interest in the co-generation assets, with a net book value of approximately $93 million, located at the 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 the Company's credit rating to below investment grade by two of the three rating agencies.

There are certain contracts that have required or could require collateral, but not accelerated payment, in the event of a credit rating change to BBB and/or Baa2 or below. These contracts are for physical electricity purchases and sales, fuel transportation and storage, energy price risk management, and transmission. At December 31, 2017, the maximum amount of potential collateral requirements under these contracts at a rating of BBB and/or Baa2 or BBB- and/or Baa3 was not material. The maximum potential collateral requirements at a rating below BBB- and/or Baa3 equaled approximately $241 million.

Included in these amounts are certain agreements that could require collateral in the event that Alabama Power or Georgia Power has a credit rating change to below investment grade. Generally, collateral may be provided by a Southern Company guaranty, letter of credit, or cash. Additionally, a credit rating downgrade could impact the ability of the Company to access capital markets, or at a minimum the cost at which it does so.

On March 1, 2017, Moody's downgraded the senior unsecured debt rating of the Company to Ba1 from Baa3.

On March 24, 2017, S&P revised its consolidated credit rating outlook for Southern Company and its subsidiaries (including the Company) from stable to negative.

On March 30, 2017, Fitch placed the ratings of the Company on rating watch negative.

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

While it is unclear how the credit rating agencies, the FERC, and the Mississippi PSC 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, including the Company, may be negatively impacted. Absent actions by Southern Company and its subsidiaries, including the Company, to mitigate the resulting impacts, which, among other alternatives, could include adjusting capital structure and/or monetizing regulatory assets, the Company's credit ratings could be negatively affected. See Note 3 to the financial statements under "Retail Regulatory Matters" for additional information.

Market Price Risk

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

To mitigate future exposure to a change in interest rates, the Company may enter into derivatives that have been designated as hedges. The weighted average interest rate on $40 million of long-term variable interest rate exposure at December 31, 2017 was 2.49%. If the Company sustained a 100 basis point change in interest rates for all long-term variable interest rate exposure, the change would have an immaterial effect on annualized interest expense at December 31, 2017. See Note 1 to the financial statements under "Financial Instruments" and Note 10 to the financial statements for additional information.

MANAGEMENT'S DISCUSSION AND ANALYSIS (continued)
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To mitigate residual risks relative to movements in electricity prices, the Company enters into physical fixed-price contracts for the purchase and sale of electricity through the wholesale electricity market and, to a lesser extent, financial hedge contracts for natural gas purchases. The Company continues to manage retail fuel-hedging programs implemented per the guidelines of the Mississippi PSC and wholesale fuel-hedging programs under agreements with wholesale customers. The Company had no material change in market risk exposure for the year ended December 31, 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 | $(7) | $ (47 ) |
| Contracts realized or settled | 8 | 29 |
| Current period changes(*) | (8 ) | 11 |
| Contracts outstanding at the end of the period, assets (liabilities), net | $(7) | $ (7 ) |

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

The net hedge volumes of energy-related derivative contracts, all of which are natural gas swaps, for the years ended December 31 were as follows:

| | 2017 | 2016 |
|---|---|---|
| | mmBtu Volume (in millions) | |
| Total hedge volume | 53 | 36 |

For natural gas hedges, the weighted average swap contract cost above market prices was approximately $0.14 per mmBtu as of December 31, 2017 and $0.19 per mmBtu as of December 31, 2016. The options outstanding were immaterial for the reporting periods presented. The costs associated with natural gas hedges are recovered through the Company's ECMs.

At December 31, 2017 and 2016, substantially all of the Company's energy-related derivative contracts were designated as regulatory hedges and were related to the Company's fuel-hedging program. Therefore, gains and losses are initially recorded as regulatory liabilities and assets, respectively, and then are included in fuel expense as they are recovered through the ECM clause.

The Company uses over-the-counter contracts that are not exchange traded but are fair valued using prices which are market observable, and thus fall into Level 2 of the fair value hierarchy. See Note 9 to the financial statements for further discussion of fair value measurements. The maturities of the energy-related derivative contracts, which are all Level 2 of the fair value hierarchy, at December 31, 2017 were as follows:

| | Fair Value Measurements December 31, 2017 | | |
|---|---|---|---|
| | Total | Maturity | |
| | Fair Value | Year 1 | Years 2&3 |
| | (in millions) | | |
| Level 1 | $ — | $ — | $ — |
| Level 2 | (7 ) | (5 ) | (2 ) |

| | | | |
|---|---|---|---|
| Level 3 | — | — | — |
| Fair value of contracts outstanding at end of period | $ (7 ) | $ (5 ) | $ (2 ) |

The Company is exposed to market price risk in the event of nonperformance by counterparties to the energy-related derivative contracts. The Company only enters into agreements and material transactions with counterparties that have investment grade credit ratings by Moody's and S&P or with counterparties who have posted collateral to cover potential credit exposure.

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Therefore, the Company does not anticipate market risk exposure from nonperformance by the counterparties. For additional information, see Note 1 to the financial statements under "Financial Instruments" and Note 10 to the financial statements.

Capital Requirements and Contractual Obligations

Approximately $900 million will be required through December 31, 2018 to fund maturities of long-term debt. In addition, the Company has $40 million of tax-exempt variable rate demand obligations that are supported by short-term credit facilities and $50 million of fixed rate revenue bonds that were remarketed from a long-term interest rate mode to an index rate mode subsequent to December 31, 2017. See "Overview and Sources of Capital" herein for additional information.

The construction program of the Company is currently estimated to be $213 million for 2018, $199 million for 2019, $193 million for 2020, $167 million for 2021, and $118 million for 2022. These estimated program amounts also include capital expenditures covered under long-term service agreements. Estimated capital expenditures to comply with environmental laws and regulations included in these amounts are $14 million, $16 million, $17 million, $13 million, and $3 million 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 Company also anticipates costs associated with closure and monitoring of ash ponds in accordance with the CCR Rule, which are reflected in the Company's ARO liabilities. These costs, which could change as the Company continues to refine its assumptions underlying the cost estimates and evaluate the method and timing of compliance activities, are estimated to be $23 million, $7 million, $7 million, $9 million, and $12 million for the years 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 program is subject to periodic review and revision, and actual construction costs may vary from these estimates because of numerous factors. These factors include: changes in business conditions; changes in load projections; storm impacts; changes in environmental laws and regulations; the outcome of any legal challenges to the environmental rules; changes in generating plants, including unit retirements and replacements and adding or changing fuel sources at existing electric generating units, to meet regulatory requirements; changes in FERC rules and regulations; Mississippi PSC approvals; changes in the expected environmental compliance program; changes in legislation; the cost and efficiency of construction labor, equipment, and materials; project scope and design changes; and the cost of capital. In addition, there can be no assurance that costs related to capital expenditures will be fully recovered.

In addition, as discussed in Note 2 to the financial statements, the Company provides postretirement benefits to substantially all employees and funds trusts to the extent required by the FERC.

Other funding requirements related to obligations associated with scheduled maturities of long-term debt, as well as the related interest, derivative obligations, preferred stock dividends, unrecognized tax benefits, pension and other post-retirement benefit plans, leases, and other purchase commitments are detailed in the contractual obligations table that follows. See Notes 1, 2, 5, 6, 7, and 10 to the financial statements for additional information.

MANAGEMENT'S DISCUSSION AND ANALYSIS (continued)
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Contractual Obligations

Contractual obligations at December 31, 2017 were as follows:

| | 2018 | 2019-2020 | 2021-2022 | After 2022 | Total |
|---|---|---|---|---|---|
| | (in millions) | | | | |
| Long-term debt[(a)] — | | | | | |
| Principal | $990 | $ 125 | $ 270 | $673 | $2,058 |
| Interest | 86 | 106 | 79 | 552 | 823 |
| Preferred stock dividends[(b)] | 2 | 3 | 3 | — | 8 |
| Financial derivative obligations[(c)] | 6 | 3 | — | — | 9 |
| Operating leases[(d)] | 3 | 5 | 4 | 7 | 19 |
| Purchase commitments — | | | | | |
| Capital[(e)] | 213 | 379 | 269 | — | 861 |
| Fuel[(f)] | 280 | 329 | 191 | 175 | 975 |
| Long-term service agreements[(g)] | 33 | 75 | 49 | 245 | 402 |
| Purchased power[(h)] | 11 | 29 | 36 | 454 | 530 |
| Pension and other postretirement benefits plans[(i)] | 7 | 15 | — | — | 22 |
| Total | $1,631 | $ 1,069 | $ 901 | $2,106 | $5,707 |

(a) All amounts are reflected based on final maturity dates except for amounts related to certain revenue bonds. The Company plans to continue, when economically feasible, to retire higher-cost securities and replace these obligations with lower-cost capital if market conditions permit. Variable rate interest obligations are estimated based on rates as of 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). For additional information, see Note 6 to the financial statements.

(b) Preferred stock does not mature; therefore, amounts are provided for the next five years only.

(c) Derivative obligations are for energy-related derivatives. For additional information, see Notes 1 and 10 to the financial statements.

(d) See Note 7 to the financial statements for additional information.

(e) The Company provides estimated capital expenditures for a five-year period, including capital expenditures associated with environmental regulations. At December 31, 2017, significant purchase commitments were outstanding in connection with the construction program. These amounts exclude capital expenditures covered under long-term service agreements, which are reflected separately. See FUTURE EARNINGS POTENTIAL – "Environmental Matters" for additional information.

(f) Fuel commitments include coal and natural gas purchases, 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.

(g) Long-term service agreements include price escalation based on inflation indices.

(h) Purchased power represents estimated minimum long-term commitments for the purchase of solar energy. Energy costs associated with solar PPAs are recovered through the fuel clause. See Notes 3 and 7 to the financial statements for additional information.

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

MANAGEMENT'S DISCUSSION AND ANALYSIS (continued)
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Cautionary Statement Regarding Forward-Looking Statements

The Company's 2017 Annual Report contains forward-looking statements. Forward-looking statements include, among other things, statements concerning retail rates, customer and sales growth, economic conditions, fuel and environmental cost recovery and other rate actions, current and proposed environmental regulations and related compliance plans and estimated expenditures, pending or potential litigation matters, access to sources of capital, projections for the qualified pension plan and postretirement benefit plans contributions, financing activities, filings with state and federal regulatory authorities, impacts of the Tax Reform Legislation, federal income tax benefits, estimated sales and purchases under power sale and purchase agreements, storm damage cost recovery and repairs, and estimated construction and other plans and expenditures. In some cases, forward-looking statements can be identified by terminology such as "may," "will," "could," "should," "expects," "plans," "anticipates," "believes," "estimates," "projects," "predicts," "potential," or "continue" or the negative of these terms or other similar terminology. There are various factors that could cause actual results to differ materially from those suggested by the forward-looking statements; accordingly, there can be no assurance that such indicated results will be realized. These factors include:

- the impact of recent and future federal and state regulatory changes, including environmental laws 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 Company is 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 Company;
- 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 Company operates;
- variations in demand for electricity, 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 fuels;
- effects of inflation;
- the ability to control costs and avoid cost overruns during the development and construction of facilities, to construct facilities in accordance with the requirements of permits and licenses, and to satisfy any environmental performance standards, including the requirements of any tax incentives;
- investment performance of the Company's employee and retiree benefit plans;
- advances in technology;
- state and federal rate regulations and the impact of pending and future rate cases and negotiations, including rate actions relating to fuel and other cost recovery mechanisms;
- the ability to successfully operate generating, transmission, and distribution facilities and the successful performance of necessary corporate functions;
- litigation related to the Kemper County energy facility;
- internal restructuring or other restructuring options that may be pursued;
- potential business strategies, including acquisitions or dispositions of assets or businesses, which cannot be assured to be completed or beneficial to the Company;
- the ability of counterparties of the Company to make payments as and when due and to perform as required;
- the ability to obtain new short- and long-term contracts with wholesale customers;
- the direct or indirect effect on the Company's business resulting from cyber intrusion or physical attack and the threat of physical attacks;
-

interest rate fluctuations and financial market conditions and the results of financing efforts;

- changes in the Company's credit ratings, including impacts on interest rates, access to capital markets, and collateral requirements;
- the impacts of any sovereign financial issues, including impacts on interest rates, access to capital markets, impacts on foreign currency exchange rates, counterparty performance, and the economy in general;
- the ability of the Company to obtain additional generating capacity (or sell excess generating capacity) at competitive prices;

- catastrophic events such as fires, earthquakes, explosions, floods, tornadoes, hurricanes and other storms, droughts, pandemic health events such as influenzas, or other similar occurrences;
- the direct or indirect effects on the Company's business resulting from incidents affecting the U.S. electric grid or operation of generating resources;
- the effect of accounting pronouncements issued periodically by standard-setting bodies; and
- other factors discussed elsewhere herein and in other reports filed by the Company from time to time with the SEC.

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

STATEMENTS OF OPERATIONS
For the Years Ended December 31, 2017, 2016, and 2015
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| | 2017 | 2016 | 2015 |
|---|---|---|---|
| | (in millions) | | |
| Operating Revenues: | | | |
| Retail revenues | $854 | $859 | $776 |
| Wholesale revenues, non-affiliates | 259 | 261 | 270 |
| Wholesale revenues, affiliates | 56 | 26 | 76 |
| Other revenues | 18 | 17 | 16 |
| Total operating revenues | 1,187 | 1,163 | 1,138 |
| Operating Expenses: | | | |
| Fuel | 395 | 343 | 443 |
| Purchased power | 25 | 34 | 12 |
| Other operations and maintenance | 282 | 312 | 274 |
| Depreciation and amortization | 161 | 132 | 123 |
| Taxes other than income taxes | 104 | 109 | 94 |
| Estimated loss on Kemper IGCC | 3,362 | 428 | 365 |
| Total operating expenses | 4,329 | 1,358 | 1,311 |
| Operating Loss | (3,142) | (195) | (173) |
| Other Income and (Expense): | | | |
| Allowance for equity funds used during construction | 72 | 124 | 110 |
| Interest expense, net of amounts capitalized | (42) | (74) | (7) |
| Other income (expense), net | (8) | (7) | (8) |
| Total other income and (expense) | 22 | 43 | 95 |
| Loss Before Income Taxes | (3,120) | (152) | (78) |
| Income taxes (benefit) | (532) | (104) | (72) |
| Net Loss | (2,588) | (48) | (6) |
| Dividends on Preferred Stock | 2 | 2 | 2 |
| Net Loss After Dividends on Preferred Stock | $(2,590) | $(50) | $(8) |

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

STATEMENTS OF COMPREHENSIVE INCOME (LOSS)
For the Years Ended December 31, 2017, 2016, and 2015
Mississippi Power Company 2017 Annual Report

| | 2017 | 2016 | 2015 |
|---|---|---|---|
| | (in millions) | | |
| Net Loss | $(2,588) | $(48) | $(6) |
| Other comprehensive income (loss): | | | |
| Qualifying hedges: | | | |
| Changes in fair value, net of tax of $(1), $1, and $-, respectively | (1) | 1 | — |
| Reclassification adjustment for amounts included in net income, net of tax of $1, $1, and $1, respectively | 1 | 1 | 1 |
| Total other comprehensive income (loss) | — | 2 | 1 |
| Comprehensive Loss | $(2,588) | $(46) | $(5) |

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

STATEMENTS OF CASH FLOWS
For the Years Ended December 31, 2017, 2016, and 2015
Mississippi Power Company 2017 Annual Report

| | 2017 | 2016 | 2015 |
|---|---|---|---|
| | (in millions) | | |
| Operating Activities: | | | |
| Net loss | $(2,588) | $(48) | $(6) |
| Adjustments to reconcile net loss to net cash provided from operating activities — | | | |
| Depreciation and amortization, total | 198 | 157 | 126 |
| Deferred income taxes | (727) | (67) | 777 |
| Investment tax credits | — | — | (210) |
| Allowance for equity funds used during construction | (72) | (124) | (110) |
| Pension and postretirement funding | — | (47) | — |
| Regulatory assets associated with Kemper IGCC | (19) | (12) | (61) |
| Estimated loss on Kemper IGCC | 3,179 | 428 | 365 |
| Income taxes receivable, non-current | — | — | (544) |
| Other, net | (12) | (20) | 8 |
| Changes in certain current assets and liabilities — | | | |
| -Receivables | 540 | 13 | 28 |
| -Fossil fuel stock | 24 | 4 | (4) |
| -Prepaid income taxes | — | 39 | (35) |
| -Other current assets | (13) | (12) | (14) |
| -Accounts payable | (3) | (14) | (34) |
| -Accrued interest | (29) | 27 | (2) |
| -Accrued taxes | 80 | 14 | (11) |
| -Over recovered regulatory clause revenues | (51) | (45) | 96 |
| -Mirror CWIP | — | — | (271) |
| -Customer liability associated with Kemper refunds | (1) | (73) | 73 |
| -Other current liabilities | (3) | 9 | 2 |
| Net cash provided from operating activities | 503 | 229 | 173 |
| Investing Activities: | | | |
| Property additions | (429) | (798) | (857) |
| Construction payables | (47) | (26) | (9) |
| Government grant proceeds | — | 137 | — |
| Other investing activities | (28) | (10) | (40) |
| Net cash used for investing activities | (504) | (697) | (906) |
| Financing Activities: | | | |
| Decrease in notes payable, net | (18) | — | — |
| Proceeds — | | | |
| Capital contributions from parent company | 1,002 | 627 | 277 |
| Long-term debt issuance to parent company | 40 | 200 | 275 |
| Other long-term debt | — | 1,200 | — |
| Short-term borrowings | 109 | — | 505 |
| Redemptions — | | | |
| Short-term borrowings | (109) | (478) | (5) |
| Long-term debt to parent company | (591) | (225) | — |
| Capital leases | (71) | (3) | (3) |
| Senior notes | (35) | (300) | — |
| Other long-term debt | (300) | (425) | (350) |

| | | | |
|---|---|---|---|
| Other financing activities | (2 ) | (2 ) | (1 ) |
| Net cash provided from financing activities | 25 | 594 | 698 |
| Net Change in Cash and Cash Equivalents | 24 | 126 | (35 ) |
| Cash and Cash Equivalents at Beginning of Year | 224 | 98 | 133 |
| Cash and Cash Equivalents at End of Year | $248 | $224 | $98 |
| Supplemental Cash Flow Information: | | | |
| Cash paid (received) during the period for — | | | |
| Interest (net of $29, $49, and $66 capitalized, respectively) | $65 | $50 | $45 |
| Income taxes (net of refunds) | (424 ) | (97 ) | (33 ) |
| Noncash transactions — | | | |
| Accrued property additions at year-end | 32 | 78 | 105 |
| Issuance of promissory note to parent related to repayment of interest-bearing refundable deposits and accrued interest | — | — | 301 |

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

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BALANCE SHEETS
At December 31, 2017 and 2016
Mississippi Power Company 2017 Annual Report

| Assets | 2017 | 2016 |
|---|---|---|
| | (in millions) | |
| Current Assets: | | |
| Cash and cash equivalents | $248 | $224 |
| Receivables — | | |
| Customer accounts receivable | 36 | 29 |
| Unbilled revenues | 41 | 42 |
| Income taxes receivable, current | 4 | 544 |
| Affiliated | 16 | 15 |
| Other accounts and notes receivable | 12 | 14 |
| Fossil fuel stock | 17 | 100 |
| Materials and supplies, current | 44 | 76 |
| Other regulatory assets, current | 125 | 115 |
| Other current assets | 9 | 8 |
| Total current assets | 552 | 1,167 |
| Property, Plant, and Equipment: | | |
| In service | 4,773 | 4,865 |
| Less: Accumulated provision for depreciation | 1,325 | 1,289 |
| Plant in service, net of depreciation | 3,448 | 3,576 |
| Construction work in progress | 84 | 2,545 |
| Total property, plant, and equipment | 3,532 | 6,121 |
| Other Property and Investments | 30 | 12 |
| Deferred Charges and Other Assets: | | |
| Deferred charges related to income taxes | 35 | 361 |
| Other regulatory assets, deferred | 437 | 518 |
| Accumulated deferred income taxes | 247 | — |
| Other deferred charges and assets | 33 | 56 |
| Total deferred charges and other assets | 752 | 935 |
| Total Assets | $4,866 | $8,235 |

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

BALANCE SHEETS
At December 31, 2017 and 2016
Mississippi Power Company 2017 Annual Report

| Liabilities and Stockholder's Equity | 2017 | 2016 |
|---|---|---|
| | (in millions) | |
| Current Liabilities: | | |
| Securities due within one year — | | |
| Parent | $— | $551 |
| Other | 989 | 78 |
| Notes payable | 4 | 23 |
| Accounts payable — | | |
| Affiliated | 59 | 62 |
| Other | 96 | 135 |
| Accrued taxes — | | |
| Accrued income taxes | 40 | — |
| Other accrued taxes | 101 | 99 |
| Unrecognized tax benefits | — | 383 |
| Accrued interest | 16 | 46 |
| Accrued compensation | 39 | 42 |
| Asset retirement obligations, current | 37 | 32 |
| Over recovered regulatory clause liabilities | — | 51 |
| Other current liabilities | 82 | 36 |
| Total current liabilities | 1,463 | 1,538 |
| Long-Term Debt (See accompanying statements) | 1,097 | 2,424 |
| Deferred Credits and Other Liabilities: | | |
| Accumulated deferred income taxes | — | 756 |
| Deferred credits related to income taxes | 372 | 7 |
| Employee benefit obligations | 116 | 115 |
| Asset retirement obligations, deferred | 137 | 146 |
| Other cost of removal obligations | 178 | 170 |
| Other regulatory liabilities, deferred | 79 | 77 |
| Other deferred credits and liabilities | 33 | 26 |
| Total deferred credits and other liabilities | 915 | 1,297 |
| Total Liabilities | 3,475 | 5,259 |
| Cumulative Redeemable Preferred Stock (See accompanying statements) | 33 | 33 |
| Common Stockholder's Equity (See accompanying statements) | 1,358 | 2,943 |
| Total Liabilities and Stockholder's Equity | $4,866 | $8,235 |
| Commitments and Contingent Matters (See notes) | | |

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

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STATEMENTS OF CAPITALIZATION
At December 31, 2017 and 2016
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| | 2017 | 2016 | 2017 | 2016 |
|---|---|---|---|---|
| | (in millions) | | (percent of total) | |
| Long-Term Debt: | | | | |
| Long-term notes payable — | | | | |
| 5.60% due 2017 | $— | $35 | | |
| 1.63% due 2018 | 50 | 50 | | |
| 5.55% due 2019 | 125 | 125 | | |
| 4.25% to 5.40% due 2035-2042 | 630 | 630 | | |
| Adjustable rate (3.05% at 12/31/17) due 2018 | 900 | 1,200 | | |
| Total long-term notes payable | 1,705 | 2,040 | | |
| Other long-term debt — | | | | |
| Pollution control revenue bonds — | | | | |
| 5.15% due 2028 | 43 | 43 | | |
| Variable rates (2.45% to 2.50% at 12/31/17) due 2018 | 40 | 40 | | |
| Plant Daniel revenue bonds (7.13%) due 2021 | 270 | 270 | | |
| Long-term debt payable to parent company (2.27%) due 2017 | — | 551 | | |
| Total other long-term debt | 353 | 904 | | |
| Capitalized lease obligations | — | 74 | | |
| Unamortized debt premium | 36 | 45 | | |
| Unamortized debt discount | (1) | (2) | | |
| Unamortized debt issuance expense | (7) | (8) | | |
| Total long-term debt (annual interest requirement — $86 million) | 2,086 | 3,053 | | |
| Less amount due within one year | 989 | 629 | | |
| Long-term debt excluding amount due within one year | 1,097 | 2,424 | 44.1 % | 44.9 % |
| Cumulative Redeemable Preferred Stock: | | | | |
| $100 par value — | | | | |
| Authorized — 1,244,139 shares | | | | |
| Outstanding — 334,210 shares | | | | |
| 4.40% to 5.25% (annual dividend requirement — $2 million) | 33 | 33 | 1.3 | 0.6 |
| Common Stockholder's Equity: | | | | |
| Common stock, without par value — | | | | |
| Authorized — 1,130,000 shares | | | | |
| Outstanding — 1,121,000 shares | 38 | 38 | | |
| Paid-in capital | 4,529 | 3,525 | | |
| Accumulated deficit | (3,205) | (616) | | |
| Accumulated other comprehensive loss | (4) | (4) | | |
| Total common stockholder's equity | 1,358 | 2,943 | 54.6 | 54.5 |
| Total Capitalization | $2,488 | $5,400 | 100.0% | 100.0% |

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

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STATEMENTS OF COMMON STOCKHOLDER'S EQUITY
For the Years Ended December 31, 2017, 2016, and 2015
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| | Number of Common Shares Issued | Common Stock | Paid-In Capital | Retained Earnings (Accumulated Deficit) | Accumulated Other Comprehensive Income (Loss) | Total |
|---|---|---|---|---|---|---|
| | (in millions) | | | | | |
| Balance at December 31, 2014 | 1 | $ 38 | $2,612 | $ (559) | $ (7) | $2,084 |
| Net loss after dividends on preferred stock | — | — | — | (8) | — | (8) |
| Capital contributions from parent company | — | — | 281 | — | — | 281 |
| Other comprehensive income (loss) | — | — | — | — | 1 | 1 |
| Other | — | — | — | 1 | — | 1 |
| Balance at December 31, 2015 | 1 | 38 | 2,893 | (566) | (6) | 2,359 |
| Net loss after dividends on preferred stock | — | — | — | (50) | — | (50) |
| Capital contributions from parent company | — | — | 632 | — | — | 632 |
| Other comprehensive income (loss) | — | — | — | — | 2 | 2 |
| Balance at December 31, 2016 | 1 | 38 | 3,525 | (616) | (4) | 2,943 |
| Net loss after dividends on preferred stock | — | — | — | (2,590) | — | (2,590) |
| Capital contributions from parent company | — | — | 1,004 | — | — | 1,004 |
| Other | — | — | — | 1 | — | 1 |
| Balance at December 31, 2017 | 1 | $ 38 | $4,529 | $ (3,205) | $ (4) | $1,358 |

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

NOTES TO FINANCIAL STATEMENTS
Mississippi Power Company 2017 Annual Report

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1. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES
General
Mississippi Power Company (the Company) is a wholly-owned subsidiary of Southern Company, which is the parent company of the Company and three other traditional electric operating companies, as well as Southern Power, Southern Company Gas (as of July 1, 2016), SCS, Southern Linc, Southern Company Holdings, Inc. (Southern Holdings), Southern Nuclear, PowerSecure, Inc. (PowerSecure) (as of May 9, 2016), and other direct and indirect subsidiaries. The traditional electric operating companies – Alabama Power, Georgia Power, Gulf Power, and the Company – are vertically integrated utilities providing electric service in four Southeastern states. The Company provides electric service to retail customers in southeast Mississippi and to wholesale customers in the Southeast. 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 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. PowerSecure is a provider of products and services in the areas of distributed generation, energy efficiency, and utility infrastructure.
The Company is subject to regulation by the FERC and the Mississippi PSC. As such, the Company's financial statements reflect the effects of rate regulation in accordance with GAAP and comply with the accounting policies and practices prescribed by its regulatory commissions. The preparation of financial statements in conformity with GAAP requires the use of estimates, and the actual results may differ from those estimates. Certain prior years' data presented in the financial statements have been reclassified to conform to the current year presentation.
Recently Issued Accounting Standards
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 the Company's revenue, including energy provided to customers, is from tariff offerings that provide electricity without a defined contractual term, as well as longer-term contractual commitments, including PPAs.
The 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 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 the Company's financial statements, if material. The 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. The Company applied the modified retrospective method of adoption effective January 1, 2018. The 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

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Mississippi Power Company 2017 Annual Report

components of contracts that would represent a lease. The accounting required by lessors is relatively unchanged. ASU 2016-02 is effective for fiscal years beginning after December 15, 2018 and the Company will adopt the new standard effective January 1, 2019.

The 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, the 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 equipment and cellular towers where the Company is the lessee and to equipment where the Company is the lessor. The Company is currently analyzing pole attachment agreements and a lease determination has not been made at this time. While the Company has not yet determined the ultimate impact, adoption of ASU 2016-02 is expected to have a significant impact on the 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, the Company recognized any excess tax benefits and deficiencies related to the exercise and vesting of stock compensation as additional paid-in capital. In addition, the new guidance requires excess tax benefits for share-based payments to be included in net cash provided from operating activities rather than net cash provided from financing activities on the statement of cash flows. The Company elected to adopt the guidance in 2016 and reflect the related adjustments as of January 1, 2016. Prior year's data presented in the financial statements has not been adjusted. The Company also elected to recognize forfeitures as they occur. The new guidance did not have a material impact on the results of operations, financial position, or cash flows of the Company. See Notes 5 and 8 for disclosures impacted by ASU 2016-09.

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 the 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. The 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. The Company adopted ASU 2017-12 effective January 1, 2018 with no material impact on its financial statements.

Affiliate Transactions

The Company has an agreement with SCS under which the following services are rendered to the Company at direct or allocated cost: general and design engineering, operations, purchasing, accounting, finance and treasury, tax, information technology, marketing, auditing, insurance and pension administration, human resources, systems and procedures, digital wireless communications, and other services with respect to business and operations, construction management, and power pool transactions. Costs for these services amounted to $140 million, $231 million, and $295 million during 2017, 2016, and 2015, respectively. Cost allocation methodologies used by SCS prior to the repeal of the Public Utility Holding Company Act of 1935, as amended, were approved by the SEC. Subsequently, additional cost allocation methodologies have been reported to the FERC and management believes they are reasonable. The FERC permits services to be rendered at cost by system service companies. See Note 7 under "Operating Leases" for additional information.

The Company has an agreement with Alabama Power under which the Company owns a portion of Greene County Steam Plant. Alabama Power operates Greene County Steam Plant, and the Company reimburses Alabama Power for its proportionate share of non-fuel expenditures and costs, which totaled $9 million, $13 million, and $11 million in 2017, 2016, and 2015, respectively. Also, the Company reimburses Alabama Power for any direct fuel purchases delivered from an Alabama Power transfer facility. There were no fuel purchases in 2017 or 2016. Fuel purchases were $8 million in 2015. The Company also has an agreement with Gulf Power under which Gulf Power owns a portion of Plant Daniel. The Company operates Plant Daniel, and Gulf Power reimburses the Company for its proportionate share of all associated expenditures and costs, which totaled $31 million, $26 million, and $27 million in 2017, 2016, and 2015, respectively. See Note 4 for additional information.

Total power purchased from affiliates through the power pool, included in purchased power in the statement of operations, totaled $16 million, $29 million, and $7 million in 2017, 2016, and 2015, respectively.

In June 2017, the Company received a capital contribution from Southern Company of $1.0 billion. The Company used a portion of the proceeds to repay all of the $591 million outstanding principal amount of promissory notes to Southern Company. See Note 6 for additional information.

On September 15, 2017, the Company issued a floating rate promissory note to Southern Company in an aggregate principal amount of up to $150 million bearing interest based on one-month LIBOR. The Company borrowed $109 million under this promissory note primarily to satisfy its federal income tax obligations for the quarter ending September 30, 2017 and subsequently repaid the promissory note upon receipt of its income tax refund from the U.S. federal government related to the settlement concerning deductible research and experimental (R&E) expenditures. See Note 5 under "Section 174 Research and Experimental Deduction" for additional information.

The Company also provides incidental services to and receives such services from other Southern Company subsidiaries which are generally minor in duration and amount. Except as described herein, the Company neither provided nor received any material services to or from affiliates in 2017, 2016, or 2015.

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

### Regulatory Assets and Liabilities

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

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

| | 2017 | 2016 | Note |
|---|---|---|---|
| | (in millions) | | |
| Retiree benefit plans – regulatory assets | $174 | $173 | (a) |
| Asset retirement obligations | 95 | 83 | (b) |
| Kemper County energy facility | 88 | 194 | (c) |
| Remaining net book value of retired assets | 44 | 53 | (d) |
| Property tax | 43 | 37 | (e) |
| Deferred charges related to income taxes | 36 | 362 | (d) |
| Plant Daniel Units 3 and 4 | 36 | 33 | (f) |
| Other regulatory assets | 28 | 28 | (g) |
| ECO carryforward | 26 | 22 | (h) |
| Other regulatory liabilities | — | (1) | (i) |
| Deferred credits related to income taxes | (377) | (9) | (j) |
| Other cost of removal obligations | (178) | (170) | (k) |
| Property damage | (57) | (68) | (l) |
| Total regulatory assets (liabilities), net | $(42) | $737 | |

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) To be recovered upon completion of removal activities over a period approved by the Mississippi PSC.

(c) Includes $114 million of regulatory assets and $26 million of regulatory liabilities to be recovered in rates over periods of eight and six years, respectively. For additional information, see Note 3 under "Kemper County Energy Facility – Rate Recovery – Kemper Settlement Agreement."

(d) Recovered over the related property lives up to 48 years.

(e) Recovered through the ad valorem tax adjustment clause over a 12-month period beginning in April of the following year. See Note 3 under "Retail Regulatory Matters – Ad Valorem Tax Adjustment" for additional information.

(f) Represents the difference between the revenue requirement under the purchase option and the revenue requirement assuming operating lease accounting treatment for the extended term, which will be amortized over a 10-year period beginning October 2021.

(g) Comprised of vacation pay, loss on reacquired debt, and other miscellaneous assets. These costs are recorded and recovered or amortized as approved by the Mississippi PSC over periods which may range up to 50 years. This amount also includes fuel-hedging assets and liabilities which are recorded over the life of the underlying hedged purchase contracts, which generally do not exceed three years. Upon final settlement, actual costs incurred are recovered through the ECM.

(h) Recovered through the ECO clause in the year following the deferral.

(i) Comprised of numerous immaterial components including deferred income tax credits and other miscellaneous liabilities that are recorded and refunded or amortized as approved by the Mississippi PSC generally over periods not exceeding one year.

(j) This amount includes excess deferred income taxes primarily associated with Tax Reform Legislation of $375 million, of which $273 million is related to protected deferred income taxes to be recovered over the related property lives utilizing the average rate assumption method in accordance with IRS normalization principles and $102 million related to unprotected (not subject to normalization) deferred income taxes to be amortized over a period approved by the Mississippi PSC or the FERC, as appropriate. Of the total excess deferred income taxes associated with Tax Reform Legislation, $129 million is associated with the Kemper County energy facility. The unprotected portion associated with the Kemper County energy facility is $54 million, of which $38 million is being amortized over eight years for retail as approved by the Mississippi PSC on February 6, 2018 and $16 million is wholesale-related. Currently, the Company is requesting eight-year amortization for the remaining portions of the unprotected deferred income taxes associated with Tax Reform Legislation in all of its retail and wholesale rate filings. See Note 3 under "Retail Regulatory Matters" and "Kemper County Energy Facility" and Note 5 for additional information.

(k) Collected in advance from customers to remove assets upon their retirement.

(l) For additional information, see Note 1 under "Provision for Property Damage."

In the event that a portion of the Company's operations is no longer subject to applicable accounting rules for rate regulation, the Company would be required to write off to income or reclassify to accumulated OCI related regulatory assets and liabilities that are not specifically recoverable through regulated rates. In addition, the Company would be required to determine if any impairment to other assets, including plant, exists and write down the assets, if impaired, to their fair values. All regulatory assets and liabilities are to be reflected in rates. See Note 3 under "Retail Regulatory Matters" and "Kemper County Energy Facility" for additional information.

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Government Grants

In 2010, the DOE, through a cooperative agreement with SCS, agreed to fund $270 million of the Kemper County energy facility through the grants awarded to the project by the DOE under the Clean Coal Power Initiative Round 2 (Initial DOE Grants). Through December 31, 2017, the Company has received grant funds of $382 million, of which $245 million of the Initial DOE Grants were used for the construction of the Kemper County energy facility, which is reflected in the Company's financial statements as a reduction to the Kemper County energy facility capital costs, and $137 million received on April 8, 2016 (Additional DOE Grants), which are expected to be used to reduce future rate impacts. An additional $2 million is expected to be received for allowable costs through December 31, 2017. See Note 3 under "Kemper County Energy Facility – Schedule and Cost Estimate" for additional information.

Revenues

Energy and other revenues are recognized as services are provided. Wholesale capacity revenues from long-term contracts are recognized at the lesser of the levelized amount or the amount billable under the contract over the respective contract period. Unbilled revenues related to retail sales are accrued at the end of each fiscal period. The Company's retail and wholesale rates include provisions to adjust billings for fluctuations in fuel costs, fuel hedging, the energy component of purchased power costs, and certain other costs. Retail rates also include provisions to adjust billings for fluctuations in costs for ad valorem taxes and certain qualifying environmental costs. Revenues are adjusted for differences between these actual costs and projected amounts billed in current regulated rates. Under or over recovered regulatory clause revenues are recorded in the balance sheets and are recovered or returned to customers through adjustments to the billing factors. The Company is required to file with the Mississippi PSC for an adjustment to the fuel cost recovery, ad valorem, and environmental factors annually.

The Company serves long-term contracts with rural electric cooperative associations and municipalities located in southeastern Mississippi under cost-based MRA electric tariffs which are subject to regulation by the FERC. The contracts with these wholesale customers represented 19.3% of the Company's total operating revenues in 2017 and are largely subject to rolling 10-year cancellation notices. Historically, these wholesale customers have acted as a group and any changes in contractual relationships for one customer are likely to be followed by the other wholesale customers.

Except as described above for the Company's cost-based MRA electric tariff customers, the Company has a diversified base of customers and no single customer or industry comprises 10% or more of revenues. For all periods presented, uncollectible accounts averaged less than 1% of revenues.

See Note 3 under "Retail Regulatory Matters" for additional information.

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 costs also include gains and/or losses from fuel-hedging programs as approved by the Mississippi PSC.

Income and Other Taxes

The Company uses the liability method of accounting for deferred income taxes and provides deferred income taxes for all significant income tax temporary differences. ITCs utilized are deferred and amortized to income over the average life of the related property. Taxes that are collected from customers on behalf of governmental agencies to be remitted to these agencies are presented net on the statements of operations.

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

Property, Plant, and Equipment

Property, plant, and equipment is stated at original cost less any regulatory disallowances and impairments. Original cost includes: materials; labor; minor items of property; appropriate administrative and general costs; payroll-related costs such as taxes, pensions, and other benefits; and the interest capitalized and cost of equity funds used during construction for projects where recovery of CWIP is not allowed in rates.

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

| | 2017 | 2016 |
|---|---|---|
| | (in millions) | |
| Generation | $2,801 | $2,632 |
| Transmission | 737 | 712 |
| Distribution | 946 | 916 |
| General | 204 | 520 |
| Plant acquisition adjustment | 85 | 85 |
| Total plant in service | $4,773 | $4,865 |

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 except for a portion of the railway track maintenance costs. The portion of railway track maintenance costs not charged to operations and maintenance expenses are charged to fuel stock and recovered through the Company's fuel clause.

Depreciation, Depletion, and Amortization

Depreciation of the original cost of utility plant in service is provided primarily by using composite straight-line rates, which approximated 3.7% in 2017, 4.2% in 2016, and 4.7% in 2015. The decrease in 2017 is primarily due to lower depreciation expense as a result of recording a loss on the lignite mine in June 2017. The decrease in the 2016 depreciation rate is primarily due to fully depreciating and retiring the ARO at Plant Watson, partially offset by the increase in depreciation for the Plant Daniel scrubbers for a full year. See "Asset Retirement Obligations and Other Costs of Removal" herein for additional information. Depreciation studies are conducted periodically to update the composite rates. The Mississippi PSC approved the 2014 study, with new rates effective January 1, 2015. When property subject to depreciation is retired or otherwise disposed of in the normal course of business, its original cost, together with the cost of removal, less salvage, is charged to accumulated depreciation. Minor items of property included in the original cost of the plant are retired when the related property unit is retired. Depreciation includes an amount for the expected cost of removal of facilities, except for the Kemper County energy facility combined cycle and related assets in service.

Asset Retirement Obligations and Other Costs of Removal

AROs are computed as the present value of the estimated ultimate costs for an asset's future retirement and are recorded in the period in which the liability is incurred. The costs are capitalized as part of the related long-lived asset and depreciated over the asset's useful life. In the absence of quoted market prices, AROs are estimated using present value techniques in which estimates of future cash outlays associated with the asset retirements are discounted using a credit-adjusted risk-free rate. Estimates of the timing and amounts of future cash outlays are based on projections of when and how the assets will be retired and the cost of future removal activities. The Company has received accounting guidance from the Mississippi PSC allowing the continued accrual of other future retirement costs for long-lived assets that the Company does not have a legal obligation to retire. Accordingly, the accumulated removal costs for these obligations are reflected in the balance sheets as a regulatory liability.

The liability for AROs primarily relates to facilities that are subject to the Disposal of Coal Combustion Residuals from Electric Utilities final rule published by the EPA in 2015 (CCR Rule), principally ash ponds. In addition, the Company has retirement obligations related to various landfill sites, underground storage tanks, deep injection wells, water wells, substation removal, mine reclamation, and asbestos removal. The Company also has identified AROs related to certain transmission and distribution facilities and certain wireless communication towers. However, liabilities for the removal of these assets have not been recorded because the settlement timing for the AROs related to these assets is indeterminable and, therefore, the fair value of the AROs 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 operations allowed removal costs in accordance with its regulatory treatment. Any differences between costs recognized in accordance with accounting standards related to asset retirement and environmental obligations and those reflected in rates are recognized as either a regulatory asset or liability, as ordered by the Mississippi PSC, and are reflected in the balance sheets.

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

| | 2017 | 2016 |
|---|---|---|
| | (in millions) | |
| Balance at beginning of year | $179 | $177 |
| Liabilities incurred | — | 15 |
| Liabilities settled | (23) | (23) |
| Accretion | 5 | 5 |
| Cash flow revisions | 13 | 5 |
| Balance at end of year | $174 | $179 |

The increase in cash flow revisions in 2017 is primarily related to a revision in the closure date of the lignite mine ARO.
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 Company will continue to periodically update these cost estimates as necessary.
Allowance for Funds Used During Construction
The Company records AFUDC, which represents the estimated debt and equity costs of capital funds that are necessary to finance the construction of new regulated facilities. While cash is not realized currently, AFUDC increases the revenue requirement and is recovered over the service life of the plant through a higher rate base and higher depreciation. The equity component of AFUDC is not included in the calculation of taxable income. The average annual AFUDC rate was 6.7%, 6.5%, and 5.99% for the years ended December 31, 2017, 2016, and 2015, respectively. AFUDC equity was $72 million, $124 million, and $110 million in 2017, 2016, and 2015, respectively. The decrease in 2017 resulted from the Kemper IGCC project suspension in June 2017.
Impairment of Long-Lived Assets and Intangibles
The Company evaluates long-lived assets for impairment when events or changes in circumstances indicate that the carrying value of such assets may not be recoverable. The determination of whether an impairment has occurred is based on either a specific regulatory disallowance or an estimate of undiscounted future cash flows attributable to the assets, as compared with the carrying value of the assets. If an impairment has occurred, the amount of the impairment recognized is determined by either the amount of regulatory disallowance or by estimating the fair value of the assets and recording a loss if the carrying value is greater than the fair value. For assets identified as held for sale, the carrying value is compared to the estimated fair value less the cost to sell in order to determine if an impairment loss is required. Until the assets are disposed of, their estimated fair value is re-evaluated when circumstances or events change.
Provision for Property Damage
The Company carries insurance for the cost of certain types of damage to generation plants and general property. However, the Company is self-insured for the cost of storm, fire, and other uninsured casualty damage to its property, including transmission and distribution facilities. As permitted by the Mississippi PSC and the FERC, the Company accrues for the cost of such damage through an annual expense accrual credited to regulatory liability accounts for the retail and wholesale jurisdictions. The cost of repairing actual damage resulting from such events that individually exceed $50,000 is charged to the reserve. Every three years the Mississippi PSC, the MPUS, and the Company will agree on SRR revenue level(s) for the ensuing period, based on historical data, expected exposure, type and amount of insurance coverage, excluding insurance cost, and any other relevant information. The accrual amount and the reserve balance are determined based on the SRR revenue level(s). If a significant change in circumstances occurs, then the SRR revenue level can be adjusted more frequently if the Company and the MPUS or the Mississippi PSC deem the change appropriate. The property damage reserve accrual will be the difference between the approved SRR revenues and the SRR revenue requirement, excluding any accrual to the reserve. In addition, SRR allows the Company to set

up a regulatory asset, pending review, if the allowable actual retail property damage costs exceed the amount in the retail property damage reserve. The Company made retail accruals of $3 million, $4 million, and $3 million for 2017, 2016, and 2015, respectively. The Company also accrued $0.3 million annually in 2017, 2016, and 2015 for the wholesale jurisdiction. As of December 31, 2017, the property damage reserve balances were $56 million and $1 million for retail and wholesale, respectively.

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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, mining, and generating plant materials. Materials are charged to inventory when purchased and then expensed, capitalized to plant, or charged to fuel stock, as used, at weighted-average cost when utilized.
Fuel Inventory
Fuel inventory includes the average cost of coal, natural gas, oil, transportation, and emissions allowances. Fuel costs are recorded to inventory when purchased, and then expensed, at weighted average cost, as used and recovered by the Company through fuel cost recovery rates. The retail rate is approved by the Mississippi PSC and the wholesale rates are approved by the FERC. Emissions allowances granted by the EPA are included in inventory at zero cost.
Financial Instruments
The Company uses derivative financial instruments to limit exposure to fluctuations in interest rates, the prices of certain fuel purchases, and electricity purchases and sales. All derivative financial instruments are recognized as either assets or liabilities on the balance sheets (included in "Other" or shown separately as "Risk Management Activities") and are measured at fair value. See Note 9 for additional information regarding fair value. Substantially all of the Company's bulk energy purchases and sales contracts that meet the definition of a derivative are excluded from the fair value accounting requirements because they qualify for the "normal" scope exception, and are accounted for under the accrual method. Fuel and interest rate derivative contracts that qualify as cash flow hedges of anticipated transactions or are recoverable through the Mississippi PSC approved fuel-hedging program as discussed below result in the deferral of related gains and losses in OCI or regulatory assets and liabilities, respectively, until the hedged transactions occur. 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 operations. Cash flows from derivatives are classified on the statement of cash flows in the same category as the hedged item. See Note 10 for additional information regarding derivatives.
The Company offsets fair value amounts recognized for multiple derivative instruments executed with the same counterparty under a netting arrangement. Additionally, the Company's collateral repayment obligations or rights to reclaim collateral arising from derivative instruments recognized at December 31, 2017 are immaterial.
The Company has an ECM clause which, among other things, allows the Company to utilize financial instruments to hedge its fuel commitments. Changes in the fair value of these financial instruments are recorded as regulatory assets or liabilities. Amounts paid or received as a result of financial settlement of these instruments are classified as fuel expense and are included in the ECM factor applied to customer billings. The Company's jurisdictional wholesale customers have a similar ECM mechanism, which has been approved by the FERC.
The 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 reclassifications for amounts included in net income.
Variable Interest Entities
The primary beneficiary of a variable interest entity (VIE) is required to consolidate the VIE when it has both the power to direct the activities of the VIE that most significantly impact the VIE's economic performance and the obligation to absorb losses or the right to receive benefits from the VIE that could potentially be significant to the

VIE.

The Company was required to provide financing for all costs associated with the mine development and operation under a contract with Liberty Fuels Company, LLC, a subsidiary of North American Coal Corporation (Liberty Fuels), in conjunction with the construction of the Kemper County energy facility. Liberty Fuels qualified as a VIE for which the Company was the primary beneficiary. As of December 31, 2016, the VIE consolidation resulted in an ARO asset and associated liability in the

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amounts of $20 million and $24 million, respectively. As of December 31, 2017, the VIE consolidation resulted in an ARO liability in the amount of $38 million. The associated ARO asset was included as part of an additional charge to income in 2017 as a result of the Company's assessment of the probability of disallowance by the Mississippi PSC. See Note 3 under "Kemper County Energy Facility" for additional information.

2. RETIREMENT BENEFITS

The Company has a defined benefit, trusteed, pension plan covering substantially all employees. This qualified pension plan is funded in accordance with requirements of the Employee Retirement Income Security Act of 1974, as amended (ERISA). No contributions to the qualified pension plan were made for the year ended December 31, 2017 and no mandatory contributions to the qualified pension plan are anticipated for the year ending December 31, 2018. The Company also provides certain defined benefit pension plans for a selected group of management and highly compensated employees. Benefits under these non-qualified pension plans are funded on a cash basis. In addition, the Company provides certain medical care and life insurance benefits for retired employees through other postretirement benefit plans. The Company funds its other postretirement trusts to the extent required by the FERC. For the year ending December 31, 2018, no other postretirement trust contributions are expected.

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Actuarial Assumptions

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

| Assumptions used to determine net periodic costs: | 2017 | 2016 | 2015 |
|---|---|---|---|
| Pension plans | | | |
| Discount rate – benefit obligations | 4.44% | 4.69% | 4.17% |
| Discount rate – interest costs | 3.81 | 3.97 | 4.17 |
| Discount rate – service costs | 4.83 | 5.04 | 4.49 |
| Expected long-term return on plan assets | 7.95 | 8.20 | 8.20 |
| Annual salary increase | 4.46 | 4.46 | 3.59 |
| Other postretirement benefit plans | | | |
| Discount rate – benefit obligations | 4.22% | 4.47% | 4.03% |
| Discount rate – interest costs | 3.55 | 3.66 | 4.03 |
| Discount rate – service costs | 4.65 | 4.88 | 4.38 |
| Expected long-term return on plan assets | 6.88 | 7.07 | 7.23 |
| Annual salary increase | 4.46 | 4.46 | 3.59 |

| Assumptions used to determine benefit obligations: | 2017 | 2016 |
|---|---|---|
| Pension plans | | |
| Discount rate | 3.80% | 4.44% |
| Annual salary increase | 4.46 | 4.46 |
| Other postretirement benefit plans | | |
| Discount rate | 3.68% | 4.22% |
| Annual salary increase | 4.46 | 4.46 |

The Company estimates the expected rate of return on pension plan and other postretirement benefit plan assets using a financial model to project the expected return on each current investment portfolio. The analysis projects an expected rate of return on each of 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.

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

| | 1 Percent Increase | 1 Percent Decrease |
|---|---|---|
| | (in millions) | |
| Benefit obligation | $ 5 | $ 5 |
| Service and interest costs | — | — |

Pension Plans

The total accumulated benefit obligation for the pension plans was $541 million at December 31, 2017 and $479 million 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:

| | 2017 | 2016 |
|---|---|---|
| | (in millions) | |
| Change in benefit obligation | | |
| Benefit obligation at beginning of year | $534 | $500 |
| Service cost | 15 | 13 |
| Interest cost | 20 | 19 |
| Benefits paid | (22 ) | (20 ) |
| Actuarial (gain) loss | 55 | 22 |
| Balance at end of year | 602 | 534 |
| Change in plan assets | | |
| Fair value of plan assets at beginning of year | 499 | 430 |
| Actual return (loss) on plan assets | 84 | 39 |
| Employer contributions | 2 | 50 |
| Benefits paid | (22 ) | (20 ) |
| Fair value of plan assets at end of year | 563 | 499 |
| Accrued liability | $(39 ) | $(35 ) |

At December 31, 2017, the projected benefit obligations for the qualified and non-qualified pension plans were $571 million and $31 million, respectively. All pension plan assets are related to the qualified pension plan.

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

| | 2017 | 2016 |
|---|---|---|
| | (in millions) | |
| Other regulatory assets, deferred | $158 | $154 |
| Other current liabilities | (3) | (3) |
| Employee benefit obligations | (36) | (32) |

Presented below are the amounts included in 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.

| | 2017 | 2016 | Estimated Amortization in 2018 |
|---|---|---|---|
| | (in millions) | | |
| Prior service cost | $3 | $3 | $ — |
| Net (gain) loss | 155 | 151 | 10 |
| Regulatory assets | $158 | $154 | |

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:

| | 2017 | 2016 |
|---|---|---|
| | (in millions) | |
| Regulatory assets: | | |
| Beginning balance | $154 | $144 |
| Net (gain) loss | 12 | 16 |
| Change in prior service costs | — | 2 |
| Reclassification adjustments: | | |
| Amortization of prior service costs | (1) | (1) |
| Amortization of net gain (loss) | (7) | (7) |
| Total reclassification adjustments | (8) | (8) |
| Total change | 4 | 10 |
| Ending balance | $158 | $154 |

Components of net periodic pension cost were as follows:

| | 2017 | 2016 | 2015 |
|---|---|---|---|
| | (in millions) | | |
| Service cost | $15 | $13 | $13 |
| Interest cost | 20 | 19 | 21 |
| Expected return on plan assets | (40) | (35) | (33) |
| Recognized net (gain) loss | 7 | 7 | 10 |
| Net amortization | 1 | 1 | 1 |
| Net periodic pension cost | $3 | $5 | $12 |

Net periodic pension cost is the sum of service cost, interest cost, and other costs netted against the expected return on plan assets. The expected return on plan assets is determined by multiplying the expected rate of return on plan assets and the market-related value of plan assets. In determining the market-related value of plan assets, the Company has elected to amortize changes in the market value of all plan assets over five years rather than recognize the changes immediately. As a result, the accounting value of plan assets that is used to calculate the expected return on plan assets differs from the current fair value of the plan assets.

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Future benefit payments reflect expected future service and are estimated based on assumptions used to measure the projected benefit obligation for the pension plans. At December 31, 2017, estimated benefit payments were as follows:

| | Benefit Payments (in millions) |
|---|---|
| 2018 | $ 23 |
| 2019 | 24 |
| 2020 | 26 |
| 2021 | 27 |
| 2022 | 28 |
| 2023 to 2027 | 164 |

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:

| | 2017 | 2016 |
|---|---|---|
| | (in millions) | |
| Change in benefit obligation | | |
| Benefit obligation at beginning of year | $97 | $97 |
| Service cost | 1 | 1 |
| Interest cost | 3 | 3 |
| Benefits paid | (6 ) | (6 ) |
| Actuarial (gain) loss | 1 | 1 |
| Retiree drug subsidy | 1 | 1 |
| Balance at end of year | 97 | 97 |
| Change in plan assets | | |
| Fair value of plan assets at beginning of year | 23 | 23 |
| Actual return (loss) on plan assets | 3 | 1 |
| Employer contributions | 4 | 4 |
| Benefits paid | (5 ) | (5 ) |
| Fair value of plan assets at end of year | 25 | 23 |
| Accrued liability | $(72) | $(74) |

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:

| | 2017 | 2016 |
|---|---|---|
| | (in millions) | |
| Other regulatory assets, deferred | $18 | $21 |
| Other regulatory liabilities, deferred | (1 ) | (2 ) |
| Employee benefit obligations | (72 ) | (74 ) |

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Approximately $17 million and $19 million was included in net regulatory assets at December 31, 2017 and 2016, respectively, related to the net loss for the other postretirement benefit plans that had not yet been recognized in net periodic other postretirement benefit cost. The estimated amortization of such amounts for 2018 is $1 million.

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:

| | 2017 | 2016 |
|---|---|---|
| | (in millions) | |
| Net regulatory assets (liabilities): | | |
| Beginning balance | $19 | $18 |
| Net (gain) loss | (1) | 2 |
| Reclassification adjustments: | | |
| Amortization of net gain (loss) | (1) | (1) |
| Total reclassification adjustments | (1) | (1) |
| Total change | (2) | 1 |
| Ending balance | $17 | $19 |

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

| | 2017 | 2016 | 2015 |
|---|---|---|---|
| | (in millions) | | |
| Service cost | $1 | $1 | $1 |
| Interest cost | 3 | 3 | 4 |
| Expected return on plan assets | (1) | (1) | (2) |
| Net amortization | 1 | 1 | 1 |
| Net periodic postretirement benefit cost | $4 | $4 | $4 |

Future benefit payments, including prescription drug benefits, reflect expected future service and are estimated based on assumptions used to measure the APBO for the other postretirement benefit plans. Estimated benefit payments are reduced by drug subsidy receipts expected as a result of the Medicare Prescription Drug, Improvement, and Modernization Act of 2003 as follows:

| | Benefit Payments | Subsidy Receipts | Total |
|---|---|---|---|
| | (in millions) | | |
| 2018 | $6 | $ — | $ 6 |
| 2019 | 6 | — | 6 |
| 2020 | 6 | (1) | 5 |
| 2021 | 7 | (1) | 6 |
| 2022 | 7 | (1) | 6 |
| 2023 to 2027 | 34 | (2) | 32 |

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 plan and the other postretirement benefit plans cover a diversified mix of assets, including equity and fixed income securities, real estate, and private equity. Derivative instruments are used primarily to gain efficient exposure to the various asset classes and as hedging tools. The Company minimizes the risk of large losses primarily through diversification but also monitors and manages other aspects of risk.

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The composition of the Company's pension plan and other postretirement benefit plan assets as of December 31, 2017 and 2016, along with the targeted mix of assets for each plan, is presented below:

| | Target | 2017 | 2016 |
|---|---|---|---|
| Pension plan assets: | | | |
| Domestic equity | 26 % | 31 % | 29 % |
| International equity | 25 | 25 | 22 |
| Fixed income | 23 | 24 | 29 |
| Special situations | 3 | 1 | 2 |
| Real estate investments | 14 | 13 | 13 |
| Private equity | 9 | 6 | 5 |
| Total | 100 % | 100 % | 100 % |
| Other postretirement benefit plan assets: | | | |
| Domestic equity | 21 % | 25 % | 23 % |
| International equity | 21 | 20 | 18 |
| Domestic fixed income | 37 | 38 | 43 |
| Special situations | 2 | 1 | 2 |
| Real estate investments | 12 | 11 | 10 |
| Private equity | 7 | 5 | 4 |
| Total | 100 % | 100 % | 100 % |

The investment strategy for plan assets related to the Company's qualified pension plan is to be broadly diversified across major asset classes. The asset allocation is established after consideration of various factors that affect the assets and liabilities of the pension plan including, but not limited to, historical and expected returns and interest rates, volatility, correlations of asset classes, the current level of assets and liabilities, and the assumed growth in assets and liabilities. Because a significant portion of the liability of the pension plan is long-term in nature, the assets are invested consistent with long-term investment expectations for return and risk. To manage the actual asset class exposures relative to the target asset allocation, the Company employs a formal rebalancing program. As additional risk management, external investment managers and service providers are subject to written guidelines to ensure appropriate and prudent investment practices. Management believes the portfolio is well-diversified with no significant concentrations of risk.

Investment Strategies

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

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

Benefit Plan Asset Fair Values

Following are the fair value measurements for the pension plan and the other postretirement benefit plan assets as of December 31, 2017 and 2016. The fair values presented are prepared in accordance with GAAP. For purposes of determining the fair value of the pension plan and other postretirement benefit plan assets and the appropriate level designation, management

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relies on information provided by the plan's trustee. This information is reviewed and evaluated by management with changes made to the trustee information as appropriate.

Valuation methods of the primary fair value measurements disclosed in the following tables are as follows:

- Domestic and international equity. Investments in equity securities such as common stocks, American depositary receipts, and real estate investment trusts that trade on a public exchange are classified as Level 1 investments and are valued at the closing price in the active market. Equity investments with unpublished prices (i.e. pooled funds) are valued as Level 2, when the underlying holdings used to value the investment are comprised of Level 1 or Level 2 equity securities.
- Fixed income. Investments in fixed income securities are generally classified as Level 2 investments and are valued based on prices reported in the market place. Additionally, the value of fixed income securities takes into consideration certain items such as broker quotes, spreads, yield curves, interest rates, and discount rates that apply to the term of a specific instrument.
- Real estate investments, private equity, and special situations investments. Investments in real estate, private equity, and special situations are generally classified as Net Asset Value as a Practical Expedient, since the underlying assets typically do not have publicly available observable inputs. The fund manager values the assets using various inputs and techniques depending on the nature of the underlying investments. Techniques may include purchase multiples for comparable transactions, comparable public company trading multiples, discounted cash flow analysis, prevailing market capitalization rates, recent sales of comparable investments, and independent third-party appraisals. The fair value of partnerships is determined by aggregating the value of the underlying assets less liabilities.

The fair values of pension plan assets as of December 31, 2017 and 2016 are presented below. These fair value measurements exclude cash, receivables related to investment income, pending investments sales, and payables related to pending investment purchases.

| | Fair Value Measurements Using | | | | |
|---|---|---|---|---|---|
| | Quoted Prices in Active Markets for Identical Assets | Significant Other Observable Inputs | Significant Unobservable Inputs | Net Asset Value as a Practical Expedient | |
| As of December 31, 2017: | (Level 1) | (Level 2) | (Level 3) | (NAV) | Total |
| | (in millions) | | | | |
| Assets: | | | | | |
| Domestic equity(*) | $113 | $ 55 | $ — | $ — | $168 |
| International equity(*) | 73 | 66 | — | — | 139 |
| Fixed income: | | | | | |
| U.S. Treasury, government, and agency bonds | — | 40 | — | — | 40 |
| Corporate bonds | — | 56 | — | — | 56 |
| Pooled funds | — | 31 | — | — | 31 |
| Cash equivalents and other | 10 | 1 | — | — | 11 |
| Real estate investments | 22 | — | — | 56 | 78 |
| Special situations | — | — | — | 9 | 9 |
| Private equity | — | — | — | 32 | 32 |
| Total | $218 | $ 249 | $ — | $ 97 | $564 |

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

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| | Fair Value Measurements Using | | | | |
|---|---|---|---|---|---|
| | Quoted Prices in Active Markets for Identical Assets | Significant Other Observable Inputs | Significant Unobservable Inputs | Net Asset Value as a Practical Expedient | |
| As of December 31, 2016: | (Level 1) | (Level 2) | (Level 3) | (NAV) | Total |
| | (in millions) | | | | |
| Assets: | | | | | |
| Domestic equity(*) | $95 | $ 44 | $ — | $ — | $139 |
| International equity(*) | 58 | 51 | — | — | 109 |
| Fixed income: | | | | | |
| U.S. Treasury, government, and agency bonds | — | 28 | — | — | 28 |
| Mortgage- and asset-backed securities | — | 1 | — | — | 1 |
| Corporate bonds | — | 46 | — | — | 46 |
| Pooled funds | — | 25 | — | — | 25 |
| Cash equivalents and other | 47 | — | — | — | 47 |
| Real estate investments | 15 | — | — | 54 | 69 |
| Special situations | — | — | — | 8 | 8 |
| Private equity | — | — | — | 26 | 26 |
| Total | $215 | $ 195 | $ — | $ 88 | $498 |

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

The fair values of 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 investments sales, and payables related to pending investment purchases.

| | Fair Value Measurements Using | | | | |
|---|---|---|---|---|---|
| | Quoted Prices in Active Markets for Identical Assets | Significant Other Observable Inputs | Significant Unobservable Inputs | Net Asset Value as a Practical Expedient | |
| As of December 31, 2017: | (Level 1) | (Level 2) | (Level 3) | (NAV) | Total |
| | (in millions) | | | | |
| Assets: | | | | | |
| Domestic equity(*) | $4 | $ 2 | $ — | $ — | $ 6 |
| International equity(*) | 3 | 2 | — | — | 5 |
| Fixed income: | | | | | |
| U.S. Treasury, government, and agency bonds | — | 5 | — | — | 5 |
| Corporate bonds | — | 2 | — | — | 2 |
| Pooled funds | — | 1 | — | — | 1 |

| | | | | | |
|---|---|---|---|---|---|
| Cash equivalents and other | 1 | — | — | — | 1 |
| Real estate investments | 1 | — | — | 2 | 3 |
| Private equity | — | — | — | 1 | 1 |
| Total | $9 | $ 12 | $ — | $ 3 | $ 24 |

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

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| | Fair Value Measurements Using | | | | |
|---|---|---|---|---|---|
| | Quoted Prices in Active Markets for Identical Assets | Significant Other Observable Inputs | Significant Unobservable Inputs | Net Asset Value as a Practical Expedient | |
| As of December 31, 2016: | (Level 1) | (Level 2) | (Level 3) | (NAV) | Total |
| | (in millions) | | | | |
| Assets: | | | | | |
| Domestic equity(*) | $4 | $ 2 | $ — | $ — | $ 6 |
| International equity(*) | 2 | 2 | — | — | 4 |
| Fixed income: | | | | | |
| U.S. Treasury, government, and agency bonds | — | 5 | — | — | 5 |
| Corporate bonds | — | 2 | — | — | 2 |
| Pooled funds | — | 1 | — | — | 1 |
| Cash equivalents and other | 2 | — | — | — | 2 |
| Real estate investments | 1 | — | — | 2 | 3 |
| Private equity | — | — | — | 1 | 1 |
| Total | $9 | $ 12 | $ — | $ 3 | $ 24 |

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

Employee Savings Plan

The Company also sponsors a 401(k) defined contribution plan covering substantially all employees. The Company matches a portion of the first 6% of employee base salary contributions. The maximum Company match is 5.1% of an employee's base salary. Total matching contributions made to the plan for 2017, 2016, and 2015 were $5 million each year.

3. CONTINGENCIES AND REGULATORY MATTERS

General Litigation Matters

The Company is subject to certain claims and legal actions arising in the ordinary course of business. In addition, the Company's business activities are subject to extensive governmental regulation related to public health and the environment, such as regulation of air emissions and water discharges. Litigation over environmental issues and claims of various types, including property damage, personal injury, common law nuisance, and citizen enforcement of environmental requirements such as 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 the Company cannot be predicted at this time; however, for current proceedings not specifically reported herein, management does not anticipate that the ultimate liabilities, if any, arising from such current proceedings would have a material effect on the Company's financial statements.

Environmental Matters

Environmental Remediation

The Company must comply with environmental laws and regulations governing the handling and disposal of waste and releases of hazardous substances. Under these various laws and regulations, the Company may also incur substantial costs to clean up affected sites. The Company has authority from the Mississippi PSC to recover approved environmental compliance costs through established regulatory mechanisms. The Company recognizes a liability for environmental remediation costs only when it determines a loss is probable and reasonably estimable.

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FERC Matters
Municipal and Rural Associations Tariff
The Company provides wholesale electric service to Cooperative Energy, East Mississippi Electric Power Association, and the City of Collins, all located in southeastern Mississippi, under a long-term cost-based, FERC regulated MRA tariff.
In March 2016, the Company reached a settlement agreement with its wholesale customers, which was subsequently approved by the FERC, for an increase in wholesale base revenues under the MRA cost-based electric tariff, primarily as a result of placing scrubbers for Plant Daniel Units 1 and 2 in service in 2015. The settlement agreement became effective for services rendered beginning May 1, 2016, resulting in an estimated annual revenue increase of $7 million under the MRA cost-based electric tariff. Additionally, under the settlement agreement, the tariff customers agreed to similar regulatory treatment for MRA tariff ratemaking as the treatment approved for retail ratemaking through an order issued by the Mississippi PSC in December 2015 (In-Service Asset Rate Order). This regulatory treatment primarily includes (i) recovery of the operational Kemper County energy facility assets providing service to customers and other related costs, (ii) amortization of the Kemper County energy facility-related regulatory assets included in rates under the settlement agreement over the 36 months ending April 30, 2019, (iii) Kemper County energy facility-related expenses included in rates under the settlement agreement no longer being deferred and charged to expense, and (iv) removing all of the Kemper County energy facility CWIP from rate base with a corresponding increase in accrual of AFUDC. The additional resulting AFUDC totaled approximately $22 million through the suspension of Kemper IGCC start-up activities and has been recorded as a charge to income.
On September 18, 2017, the Company and Cooperative Energy executed a Shared Service Agreement (SSA), as part of the MRA tariff, under which the Company and Cooperative Energy will share in providing electricity to all Cooperative Energy delivery points, in lieu of the current arrangement under which each delivery point is specifically assigned to either entity. The SSA accepted by the FERC on October 31, 2017 became effective on January 1, 2018 and may be cancelled by Cooperative Energy with 10 years notice after December 31, 2020. The SSA provides Cooperative Energy the option to decrease its use of the Company's generation services under the MRA tariff, subject to annual and cumulative caps and a one-year notice requirement. In the event Cooperative Energy elects to reduce these services, the related reduction in the Company's revenues is not expected to be significant through 2020.
Fuel Cost Recovery
The Company has a wholesale MRA and a Market Based (MB) fuel cost recovery factor. At December 31, 2017, over-recovered wholesale MRA fuel costs were immaterial and at December 31, 2016 were approximately $13 million, and is included in over-recovered regulatory clause liabilities, current in the balance sheet. Effective January 1, 2018, the wholesale MRA fuel rate increased $11 million annually.
The Company's operating revenues are adjusted for differences in actual recoverable fuel cost and amounts billed in accordance with the currently approved cost recovery rate. Accordingly, changes in the billing factor should have no significant effect on the Company's revenues or net income, but will affect cash flow.
Market-Based Rate Authority
The Company has authority from the FERC to sell electricity at market-based rates. Since 2008, that authority, for certain balancing authority areas, has been conditioned on compliance with the requirements of an energy auction, which the FERC found to be tailored mitigation that addresses potential market power concerns. In accordance with FERC regulations governing such authority, the traditional electric operating companies (including the Company) and Southern Power filed a triennial market power analysis in 2014, which included continued reliance on the energy auction as tailored mitigation. In 2015, the FERC issued an order finding that the traditional electric operating companies' (including the Company's) and Southern Power's existing tailored mitigation may not effectively mitigate the potential to exert market power in certain areas served by the traditional electric operating companies and in some adjacent areas. The FERC directed the traditional electric operating companies (including the Company) and Southern Power to show why market-based rate authority should not be revoked in these areas or to provide a mitigation plan to

further address market power concerns. The traditional electric operating companies (including the Company) and Southern Power filed a request for rehearing and filed their response with the FERC in 2015.

In December 2016, the traditional electric operating companies (including the Company) and Southern Power filed an amendment to their market-based rate tariff that proposed certain changes to the energy auction, as well as several non-tariff changes. On February 2, 2017, the FERC issued an order accepting all such changes subject to an additional condition of cost-based price caps for certain sales outside of the energy auction, finding that all of these changes would provide adequate alternative mitigation for the traditional electric operating companies' (including the Company's) and Southern Power's potential to exert market power in certain areas served by the traditional electric operating companies (including the Company) and in

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some adjacent areas. On May 17, 2017, the FERC accepted the traditional electric operating companies' (including the Company's) 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' (including the Company's) and Southern Power's June 29, 2017 triennial updated market power analysis. The FERC directed the traditional electric operating companies (including the Company) 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 (including the Company) 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.

Cooperative Energy Power Supply Agreement

In 2008, the Company entered into a 10-year Power Supply Agreement (PSA) with Cooperative Energy for approximately 152 MWs, which became effective in 2011. Following certain plant retirements, the PSA capacity was reduced to 86 MWs. On February 5, 2018, the Company and Cooperative Energy executed an amendment to extend the PSA through March 31, 2021, effective April 1, 2018, with increased total capacity of 286 MWs.

Cooperative Energy also has a 10-year Network Integration Transmission Service Agreement (NITSA) with SCS for transmission service to certain delivery points on the Company's transmission system that became effective in 2011. As a result of the PSA amendments, Cooperative Energy and SCS amended the terms of the NITSA on January 12, 2018 to provide for the purchase of incremental transmission capacity for service beginning April 1, 2018 through March 31, 2021. This NITSA amendment remains subject to acceptance by the FERC. The ultimate outcome of these matters cannot be determined at this time.

Retail Regulatory Matters

General

In 2012, the Mississippi PSC issued an order for the purpose of investigating and reviewing, for informational purposes only, the ROE formulas used by the Company and all other regulated electric utilities in Mississippi. In 2013, the MPUS filed with the Mississippi PSC its report on the ROE formulas used by the Company and all other regulated electric utilities in Mississippi.

In 2014, the Mississippi PSC issued an order for the purpose of investigating and reviewing the adoption of a uniform formula rate plan for the Company and other regulated electric utilities in Mississippi.

On January 26, 2018, the Mississippi PSC issued an order directing utilities to file within 30 days information regarding the impact on rates resulting from Tax Reform Legislation. The Company's Kemper County energy facility rates, approved on February 6, 2018, include the effects of Tax Reform Legislation. The Company's 2018 ECO, revised 2018 PEP, and 2018 SRR rate filings, all submitted in February 2018, include the effects of Tax Reform Legislation and are subject to approval by the Mississippi PSC.

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

Performance Evaluation Plan

The Company's retail base rates are set under the PEP, a rate plan approved by the Mississippi PSC. Two filings are made for each calendar year: the PEP projected filing, which is typically filed prior to the beginning of the year based on a projected revenue requirement, and the PEP lookback filing, which is filed after the end of the year and allows for review of the actual revenue requirement compared to the projected filing.

In 2011, the Company submitted its annual PEP lookback filing for 2010, which recommended no surcharge or refund. Later in 2011, the MPUS disputed certain items in the 2010 PEP lookback filing. In 2012, the Mississippi PSC issued an order canceling the Company's PEP lookback filing for 2011. In 2013, the MPUS contested the Company's PEP lookback filing for 2012, which indicated a refund due to customers of $5 million. Unresolved matters related to

the 2010 PEP lookback filing, which remain under review, also impact the 2012 PEP lookback filing.
In 2013, the Mississippi PSC approved the projected PEP filing for 2013, which resulted in a rate increase of 1.9%, or $15 million, annually, effective March 19, 2013. The Company may be entitled to $3 million in additional revenues related to 2013 as a result of the late implementation of the 2013 PEP rate increase.

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In 2014, 2015, 2016, and 2017, the Company submitted its annual PEP lookback filings for the prior years, which for 2013 and 2014 each indicated no surcharge or refund and for each of 2015 and 2016 indicated a $5 million surcharge. Additionally, in July 2016, in November 2016, and on November 15, 2017, the Company submitted its annual projected PEP filings for 2016, 2017, and 2018, respectively, which for 2016 and 2017 indicated no change in rates and for 2018 indicated a rate increase of 4%, or $38 million in annual revenues. The Mississippi PSC suspended each of these filings to allow more time for review.

On February 7, 2018, the Company revised its annual projected PEP filing for 2018 to reflect the impacts of 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%. See Note 5 for additional information.

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

Energy Efficiency

In 2013, the Mississippi PSC approved an energy efficiency and conservation rule requiring electric and gas utilities in Mississippi serving more than 25,000 customers to implement energy efficiency programs and standards. Quick Start Plans, which include a portfolio of energy efficiency programs that are intended to provide benefits to a majority of customers, were extended by an order issued by the Mississippi PSC in July 2016, until the time the Mississippi PSC approves a comprehensive portfolio plan program. The ultimate outcome of this matter cannot be determined at this time.

On July 6, 2017, the Mississippi PSC issued an order approving the Company's Energy Efficiency Cost Rider 2017 compliance filing, which increased annual retail revenues by approximately $2 million effective with the first billing cycle for August 2017.

On November 30, 2017, the Company submitted its Energy Efficiency Cost Rider 2018 compliance filing which included a small decrease in annual retail revenues. The ultimate outcome of this matter cannot be determined at this time.

Environmental Compliance Overview Plan

In 2012, the Mississippi PSC approved the Company's request for a CPCN to construct scrubbers on Plant Daniel Units 1 and 2, which were placed in service in 2015. These units are jointly owned by the Company and Gulf Power, with 50% ownership each. In 2014, the Company entered into a settlement agreement with the Sierra Club under which, among other things, the Company agreed to retire, repower with natural gas, or convert to an alternative non-fossil fuel source Plant Sweatt Units 1 and 2 (80 MWs) no later than December 2018 (and the units were retired in July 2016). The Company also agreed that it would cease burning coal and other solid fuel at Plant Watson Units 4 and 5 (750 MWs) and begin operating those units solely on natural gas no later than April 2015 (which occurred in April 2015) and cease burning coal and other solid fuel at Plant Greene County Units 1 and 2 (200 MWs) no later than April 2016 (which occurred in February and March 2016, respectively) and begin operating those units solely on natural gas (which occurred in June and July 2016, respectively).

In accordance with a 2011 accounting order from the Mississippi PSC, the Company has the authority to defer in a regulatory asset for future recovery all plant retirement- or partial retirement-related costs resulting from environmental regulations. The Mississippi PSC approved $41 million and $17 million of costs that were reclassified to regulatory assets associated with Plant Watson and Plant Greene County, respectively, for amortization over five-year periods that began in July 2016 and July 2017, respectively. As a result, these decisions are not expected to have a material impact on the Company's financial statements.

In August 2016, the Mississippi PSC approved the Company's revised ECO plan filing for 2016, which requested the maximum 2% annual increase in revenues, or approximately $18 million, primarily related to the Plant Daniel Units 1 and 2 scrubbers placed in service in 2015. The revised rates became effective with the first billing cycle for September 2016. Approximately $22 million of related revenue requirements in excess of the 2% maximum was deferred for inclusion in the 2017 filing, along with related carrying costs.

On May 4, 2017, the Mississippi PSC approved the Company's ECO plan filing for 2017, which requested the maximum 2% annual increase in revenues, or approximately $18 million, primarily related to the carryforward from the prior year. The rates became effective with the first billing cycle for June 2017. Approximately $26 million of related revenue requirements in excess of the 2% maximum was deferred for inclusion in the 2018 filing, along with related carrying costs.

On February 14, 2018, the Company submitted its ECO plan filing for 2018, including the effects of Tax Reform Legislation, which requested the maximum 2% annual increase in revenues, or approximately $17 million, primarily related to the carryforward from the prior year. Approximately $13 million of related revenue requirements in excess of the 2% maximum, along with related carrying costs, remains deferred for inclusion in the 2019 filing. The ultimate outcome of this matter cannot be determined at this time.

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Fuel Cost Recovery

The Company establishes, annually, a retail fuel cost recovery factor that is approved by the Mississippi PSC. The Company is required to file for an adjustment to the retail fuel cost recovery factor annually. On January 12, 2017, the Mississippi PSC approved the 2017 retail fuel cost recovery factor, effective February 2017 through January 2018, which resulted in an annual revenue increase of approximately $55 million. On November 15, 2017, the Company filed its annual rate adjustment under the retail fuel cost recovery clause, requesting an additional increase of $39 million annually, which the Mississippi PSC approved on January 16, 2018 effective February 2018 through January 2019. At December 31, 2017, the amount of under-recovered retail fuel costs included in the balance sheet in customer accounts receivable was approximately $6 million compared to $37 million over recovered at December 31, 2016.

The Company's operating revenues are adjusted for differences in actual recoverable fuel cost and amounts billed in accordance with the currently approved cost recovery rate. Accordingly, changes in the billing factor should have no significant effect on the Company's revenues or net income, but will affect cash flow.

Ad Valorem Tax Adjustment

The Company establishes, annually, an ad valorem tax adjustment factor that is approved by the Mississippi PSC to collect the ad valorem taxes paid by the Company. On July 6, 2017, the Mississippi PSC approved the Company's annual ad valorem tax adjustment factor filing for 2017, which included an annual rate increase of 0.85%, or $8 million in annual retail revenues, primarily due to increased assessments.

System Restoration Rider

In February 2016, the Company submitted its 2016 SRR rate filing which proposed no changes to either the SRR rate or the annual property damage reserve accrual of $3 million annually. On February 3, 2017, the Company submitted its 2017 SRR rate filing, which proposed an increase in the property damage reserve accrual of $1 million. These filings were suspended by the Mississippi PSC for review.

On January 21, 2017, a tornado caused extensive damage to the Company's transmission and distribution infrastructure. Storm damage repairs were approximately $9 million. A portion of these costs was charged to the retail property damage reserve and was addressed in the 2018 SRR rate filing.

On February 1, 2018, the Company submitted its 2018 SRR rate filing, including the effects of Tax Reform Legislation, which proposed that the SRR rate remain at zero and the annual accrual for the property damage reserve be reduced to $2 million in 2018.

The ultimate outcome of these matters cannot be determined at this time. See Note 1 under "Provision for Property Damage" for additional information.

Storm Damage Cost Recovery

In connection with the damage associated with Hurricane Katrina, the Mississippi PSC authorized the issuance of system restoration bonds in 2006. In accordance with a Mississippi PSC order on January 24, 2017, the Company eliminated the applicable Storm Restoration Charge because the bond sinking fund managed by the Mississippi State Bond Commission is substantially funded.

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 the Company 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, the Company 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. The Company 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." The Company 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, the Company 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, the Company 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 the Company 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, the Company 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 the Company, 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 DOE Grants. In the aggregate, the Company 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, the Company 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, the Company 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. The Company 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 the Company'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, the Company 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) the Company to file a reserve margin plan with the Mississippi PSC by August 2018.

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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 the Company's actual average capital structure, with a maximum common equity percentage of 49.733%, a 9.225% return on common equity, and actual embedded interest costs. The In-Service Asset Rate Order also included a prudence finding of all costs in the stipulated revenue requirement calculation for the in-service assets.
In connection with the implementation of the In-Service Asset Rate Order and wholesale rates, the Company 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 the Company 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. See "FERC Matters" herein for additional information related to the 2016 settlement agreement with wholesale customers.
Lignite Mine and $CO_2$ Pipeline Facilities
The Company 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, the Company executed a 40-year management fee contract with Liberty Fuels Company, LLC (Liberty Fuels), a wholly-owned subsidiary of The North American Coal Corporation, which developed, constructed, and is 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 the Company has a contractual obligation to fund all reclamation activities. The Company expects mine reclamation to begin in 2018. In addition to the obligation to fund the reclamation activities, the Company provided working capital support to Liberty Fuels through cash advances for capital purchases, payroll, and other operating expenses. See Note 1 under "Asset Retirement Obligations and Other Costs of Removal" and "Variable Interest Entities" for additional information.
In addition, the Company 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 the Company 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 the Company was filed in Harrison County Circuit Court (Circuit Court) by Biloxi Freezing & Processing Inc., Gulfside Casino Partnership, and John Carlton Dean, which was amended and refiled on July 11, 2016 to include, among other things, Southern Company as a defendant. The individual plaintiff alleges that the Company and Southern Company violated the Mississippi Unfair Trade Practices Act. All plaintiffs have alleged that the Company and Southern Company concealed, falsely represented, and failed to fully disclose important facts concerning the cost and schedule of the Kemper County energy facility and that these alleged breaches have unjustly enriched the Company and Southern Company. The plaintiffs seek unspecified actual damages and punitive damages; ask the Circuit Court to appoint a receiver to oversee, operate, manage, and otherwise control all affairs relating to the Kemper County energy facility; ask the Circuit Court to revoke any licenses or certificates authorizing the Company or Southern Company to engage in any business related to the Kemper 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 the Company and dismissed the case. On July 7, 2017, the plaintiffs filed notice of an appeal. The Company believes this legal challenge has no merit; however, an adverse outcome in this proceeding could have a material impact on the Company's results of operations, financial condition, and liquidity. The Company intends to vigorously defend itself in this matter and the ultimate outcome of this matter cannot be determined at this time.

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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 the Company, 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 the Company, Southern Company, and SCS and sought compensatory damages of $100 million, as well as unspecified punitive damages. Southern Company, the Company, 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, the Company reached a settlement agreement with Treetop, Greenleaf, Tenrgys, LLC, Tellus Energy, LLC, WCOA, LLC, and Tellus Operating Group and the arbitration was dismissed.

4. JOINT OWNERSHIP AGREEMENTS

The Company and Alabama Power own, as tenants in common, Units 1 and 2 (total capacity of 500 MWs) at Greene County Steam Plant, which is located in Alabama and operated by Alabama Power. Additionally, the Company and Gulf Power, own as tenants in common, Units 1 and 2 (total capacity of 1,000 MWs) at Plant Daniel, which is located in Mississippi and operated by the Company. At December 31, 2017, the Company's percentage ownership and investment in these jointly-owned facilities in commercial operation were as follows:

| Generating Plant | Company Ownership | Plant in Service | Accumulated Depreciation | CWIP |
|---|---|---|---|---|
| | | (in millions) | | |
| Greene County | | | | |
| Units 1 and 2 | 40 % | $164 | $ 55 | $ 1 |
| Daniel | | | | |
| Units 1 and 2 | 50 % | $713 | $ 189 | $ 4 |

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

5. INCOME TAXES

On behalf of the Company, Southern Company files a consolidated federal income tax return and various combined and separate state income tax returns. Under a joint consolidated income tax allocation agreement, each Southern Company subsidiary's current and deferred tax expense is computed on a stand-alone basis and no subsidiary is allocated more current expense than would be paid if it filed a separate income tax return. In accordance with IRS regulations, each company is jointly and severally liable for the federal tax liability.

Federal Tax Reform Legislation

Following the enactment of 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, the Company considers all amounts recorded in the financial statements as a result of Tax Reform Legislation to be "provisional" as discussed in SAB 118 and subject to revision. The Company is awaiting additional guidance from industry and income tax authorities in order to finalize its accounting. The ultimate impact of 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.

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Current and Deferred Income Taxes

Details of income tax provisions are as follows:

| | 2017 | 2016 | 2015 |
|---|---|---|---|
| | (in millions) | | |
| Federal — | | | |
| Current | $194 | $(31) | $(768) |
| Deferred | (753) | (60) | 704 |
| | (559) | (91) | (64) |
| State — | | | |
| Current | — | (6) | (81) |
| Deferred | 27 | (7) | 73 |
| | 27 | (13) | (8) |
| Total | $(532) | $(104) | $(72) |

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The tax effects of temporary differences between the carrying amounts of assets and liabilities in the financial statements and their respective tax bases, which give rise to deferred tax assets and liabilities, are as follows:

| | 2017 | | 2016 | |
|---|---|---|---|---|
| | (in millions) | | | |
| Deferred tax liabilities — | | | | |
| Accelerated depreciation | $ | 373 | $ | 386 |
| Property basis difference | 242 | | 852 | |
| Regulatory assets associated with AROs | 34 | | 72 | |
| Pensions and other benefits | 28 | | 49 | |
| Regulatory assets associated with employee benefit obligations | 45 | | 70 | |
| Regulatory assets associated with the Kemper County energy facility | 31 | | 82 | |
| Regulatory assets associated with Plant Daniel | 9 | | 13 | |
| Rate differential | — | | 141 | |
| Federal effect of state deferred taxes | 9 | | — | |
| Ad valorem over/under recovery | 11 | | 14 | |
| Regulatory assets for Mercury and Air Toxics Standards compliance | 11 | | 8 | |
| Other | 11 | | 91 | |
| Total | 804 | | 1,778 | |
| Deferred tax assets — | | | | |
| Fuel clause over recovered | — | | 26 | |
| Estimated loss on Kemper IGCC | 722 | | 484 | |
| Pension and other benefits | 62 | | 96 | |
| Federal NOL | 40 | | 109 | |
| Property insurance | 15 | | 27 | |
| Premium on long-term debt | 7 | | 14 | |
| AROs | 34 | | 72 | |
| Property basis difference | 70 | | — | |
| Affirmative adjustments | 31 | | — | |
| Regulatory liability associated with Tax Reform Legislation (not subject to normalization) | 27 | | — | |

| | | | |
|---|---|---|---|
| Deferred state tax assets | 133 | | 113 |
| Deferred federal tax assets | — | | 31 |
| Federal effect of state deferred taxes | — | | 19 |
| Other | 32 | | 31 |
| Total | 1,173 | | 1,022 |
| Valuation allowance (net of $35 million in federal benefit) | 122 | | — |
| Accumulated deferred income tax (assets)/liabilities | (247 | ) | 756 |

The implementation of Tax Reform Legislation significantly reduced accumulated deferred income taxes, partially offset by bonus depreciation provisions in the Protecting Americans from Tax Hikes Act. 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 were $36 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 were $376 million. These liabilities are primarily attributable to deferred taxes previously recognized at rates higher than the current enacted tax law and unamortized ITCs.

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In accordance with regulatory requirements, deferred federal ITCs are amortized over the life of the related property with such amortization normally applied as a credit to reduce depreciation in the statements of operations. Credits for non-Kemper County energy facility related deferred ITCs amortized in this manner amounted to $1 million in each of 2017, 2016, and 2015.

At December 31, 2017, the Company had state of Mississippi NOL carryforwards totaling approximately $2.8 billion, resulting in deferred tax assets of approximately $111 million. The NOLs will expire between 2031 and 2037.

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 | 0.6 | (5.7 ) | (6.3 ) |
| Non-deductible book depreciation | 0.1 | 0.7 | 1.3 |
| AFUDC-equity | — | (28.5) | (49.6) |
| Non-deductible equity portion on Kemper IGCC write-off | 5.3 | — | — |
| Tax Reform Legislation | 11.9 | — | — |
| Other | — | — | (2.9 ) |
| Effective income tax rate (benefit rate) | (17.1)% | (68.5)% | (92.5)% |

The decrease in the Company's 2017 effective tax rate (benefit rate), as compared to 2016, is primarily due to an increase in estimated losses associated with the Kemper IGCC, a decrease in non-taxable AFUDC equity, and a decrease due to the remeasurement of deferred income taxes resulting from Tax Reform Legislation. The decrease in the Company's 2016 effective tax rate (benefit rate), as compared to 2015, is primarily due to an increase in estimated losses associated with the Kemper IGCC and an increase in non-taxable AFUDC equity.

Tax Reform Legislation reduced the corporate income tax rate from 35% to 21%. As a result of implementation, the Company restated future tax benefits/deductions recorded as deferred tax assets/liabilities to reflect the new rate. The implementation resulted in a $372 million increase in tax expense and a $375 million increase in regulatory liabilities.

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 the Company's overall effective tax rate. See Note 1 under "Recently Issued Accounting Standards" for additional information.

Unrecognized Tax Benefits

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

| | 2017 | 2016 | 2015 |
|---|---|---|---|
| | (in millions) | | |
| Unrecognized tax benefits at beginning of year | $465 | $421 | $165 |
| Tax positions increase from current periods | — | 26 | 32 |
| Tax positions increase from prior periods | 2 | 18 | 224 |
| Tax positions decrease from prior periods | (177 ) | — | — |
| Reductions due to settlements | (290 ) | — | — |
| Balance at end of year | $— | $465 | $421 |

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The tax positions increases from current periods and prior periods for 2017, 2016 and 2015 relate to state tax benefits, deductions for R&E expenditures, 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 federal income tax benefits from deferred ITCs. The tax positions decrease from prior periods and reductions due to settlements for 2017 relate primarily to the settlement of R&E expenditures associated with the Kemper County energy facility. See "Section 174 Research and Experimental Deduction" herein for additional information. These amounts are presented on a gross basis without considering the related federal or state income tax impact.

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

| | 2017 | 2016 | 2015 |
|---|---|---|---|
| | (in millions) | | |
| Tax positions impacting the effective tax rate | $— | $1 | $(2 ) |
| Tax positions not impacting the effective tax rate | — | 464 | 423 |
| Balance of unrecognized tax benefits | $— | $465 | $421 |

The tax positions not 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. See "Section 174 Research and Experimental Deduction" herein for additional information.

Accrued interest for unrecognized tax benefits was as follows:

| | 2017 | 2016 | 2015 |
|---|---|---|---|
| | (in millions) | | |
| Interest accrued at beginning of year | $28 | $ 13 | $ 3 |
| Interest accrued during the year | (28 ) | 15 | 10 |
| Balance at end of year | $— | $ 28 | $ 13 |

The Company classifies interest on tax uncertainties as interest expense. The Company did not accrue any penalties on uncertain tax positions.

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

The IRS has finalized its audits of Southern Company's consolidated federal income tax returns through 2016. Southern Company is a participant in the Compliance Assurance Process of the IRS. The audits for the Company's state income tax returns have either been concluded, or the statute of limitations has expired, for years prior to 2011.

Section 174 Research and Experimental Deduction

Southern Company, on behalf of the 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 (JCT), resolving a methodology for these deductions. As a result of the JCT approval, Southern Company recognized $176 million of previously unrecognized tax benefits and reversed $36 million of associated accrued interest.

6. FINANCING

Going Concern

The Company's financial statement presentation contemplates continuation of the Company as a going concern as a result of Southern Company's anticipated ongoing financial support of the Company. Specifically, the Company has been informed by Southern Company that in the event sufficient funds are not available from external sources, Southern Company intends to provide the Company with loans and/or equity to fund the remaining indebtedness to mature and other cash needs over the next 12 months. As of December 31, 2017, the Company's current liabilities exceeded current assets by approximately $911 million primarily due to a $900 million unsecured term loan that matures on March 31, 2018. The Company expects to refinance the unsecured term loan with external security issuances and/or borrowings from financial institutions or Southern Company. To fund

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the Company's capital needs over the next 12 months, the Company intends to utilize operating cash flows, external security issuances, lines of credit, bank term loans, equity contributions from Southern Company and, to the extent necessary, loans from Southern Company.

Securities Due Within One Year

A summary of scheduled maturities and redemptions of securities due within one year at December 31, 2017 and 2016 was as follows:

| | 2017 | 2016 |
|---|---|---|
| | (in millions) | |
| Parent company loans | $— | $551 |
| Senior notes | — | 35 |
| Bank term loans | 900 | — |
| Revenue bonds(*) | 90 | 40 |
| Capitalized leases | — | 3 |
| Unamortized debt issuance expense | (1) | — |
| Outstanding at December 31 | $989 | $629 |

(*) 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: $900 million in 2018, $125 million in 2019, and $270 million in 2021. For long-term debt, other than revenue bonds, there are no scheduled maturities for 2020 and 2022.

Parent Company Loans and Equity Contributions

At December 31, 2016, the Company had $551 million of outstanding promissory notes to Southern Company.

In February 2017, the Company amended $551 million in promissory notes to Southern Company extending the maturity dates of the notes from December 1, 2017 to July 31, 2018. In the second quarter 2017, the Company borrowed an additional $40 million under a promissory note issued to Southern Company.

In June 2017, Southern Company made equity contributions totaling $1.0 billion to the Company. The Company used a portion of the proceeds to (i) prepay $300 million of the outstanding principal amount under its $1.2 billion unsecured term loan, which matures on March 30, 2018; (ii) repay all of the $591 million outstanding principal amount of promissory notes to Southern Company; and (iii) repay a $10 million short-term bank loan.

In September 2017, the Company issued a floating rate promissory note to Southern Company in an aggregate principal amount of up to $150 million bearing interest based on one-month LIBOR. The Company borrowed $109 million under this promissory note primarily to satisfy its federal income tax obligations for the quarter ending September 30, 2017 and subsequently repaid the promissory note upon receipt of its income tax refund from the U.S. federal government related to the settlement concerning deductible R&E expenditures. See Note 5 under "Section 174 Research and Experimental Deduction" for additional information. At December 31, 2017, the Company had no outstanding promissory notes to Southern Company.

Bank Term Loans

In March 2017, the Company issued a $9 million short-term bank note bearing interest at 5% per annum, which was repaid in April 2017.

In June 2017, the Company used a portion of the proceeds from Southern Company equity contributions to prepay $300 million of the outstanding principal amount under its $1.2 billion unsecured term loan, which matures on March 30, 2018, and to repay $10 million of the outstanding principal amount of bank loans. See "Parent Company Loans and Equity Contributions" herein for more information.

This unsecured term loan has a covenant that limits debt levels to 65% of total capitalization, as defined in the agreement. For purposes of this definition, debt excludes any long-term debt payable to affiliated trusts and other hybrid securities. At December 31, 2017, the Company was in compliance with its debt limit.
In August 2017, the Company repaid a $12.5 million short-term bank note.

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At December 31, 2017, the Company had a $900 million unsecured term loan outstanding, which was reflected in the statements of capitalization as securities due within one year. At December 31, 2016, the Company had a $1.2 billion unsecured term loan outstanding, which was reflected in the statements of capitalization as long-term debt.

Senior Notes

At December 31, 2017 and 2016, the Company had $755 million and $790 million of senior notes outstanding, respectively, which included senior notes due within one year. These senior notes are effectively subordinated to the secured debt of the Company. See "Plant Daniel Revenue Bonds" below for additional information regarding the Company's secured indebtedness.

Plant Daniel Revenue Bonds

In 2011, in connection with the Company's election under its operating lease of Plant Daniel Units 3 and 4 to purchase the assets, the Company 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. These bonds are secured by Plant Daniel Units 3 and 4 and certain related personal property. The bonds were recorded at fair value as of the date of assumption, or $346 million, reflecting a premium of $76 million. See "Assets Subject to Lien" herein for additional information.

Pollution Control Revenue Bonds

Pollution control obligations represent loans to the Company from public authorities of funds derived from sales by such authorities of pollution control revenue bonds issued to finance pollution control and solid waste disposal facilities. The Company is required to make payments sufficient for the authorities to meet principal and interest requirements of such bonds. The amount of tax-exempt pollution control revenue bonds outstanding at December 31, 2017 and 2016 was $83 million.

Other Revenue Bonds

Other revenue bond obligations represent loans to the Company 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.

The Company 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 long-term debt.

Capital Leases

In 2013, the Company entered into an agreement to sell the air separation unit for the Kemper County energy facility and also entered into a 20-year nitrogen supply agreement. The nitrogen supply agreement was determined to be a sale/leaseback agreement, which resulted in a capital lease obligation of $74 million at December 31, 2016. Following the suspension of the Kemper IGCC, the Company entered into an asset purchase and settlement agreement in December 2017 with the lessor, which terminated the capital lease obligation. There were no contingent rentals in the contract and a portion of the monthly payment specified in the agreement was related to executory costs for the operation and maintenance of the air separation unit and excluded from the minimum lease payments. The minimum lease payments for 2017 were $7 million. See Note 3 under "Kemper County Energy facility" for additional information.

Assets Subject to Lien

The revenue bonds assumed in conjunction with the purchase of Plant Daniel Units 3 and 4 are secured by Plant Daniel Units 3 and 4 and certain related personal property. 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 the obligations of Southern Company or another of its other subsidiaries. See "Plant Daniel Revenue Bonds" herein for additional information.

On October 4, 2017, the Company 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 its 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 the Company's credit rating to below investment grade by two of the three rating agencies.

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Outstanding Classes of Capital Stock
The Company currently has preferred stock (including depositary shares which represent one-fourth of a share of preferred stock) and common stock authorized and outstanding. The preferred stock of the Company contains a feature that allows the holders to elect a majority of the Company's board of directors if preferred dividends are not paid for four consecutive quarters. Because such a potential redemption-triggering event is not solely within the control of the Company, this preferred stock is presented as "Cumulative Redeemable Preferred Stock" in a manner consistent with temporary equity under applicable accounting standards. The Company's preferred stock and depositary preferred stock, without preference between classes, rank senior to the Company's common stock with respect to payment of dividends and voluntary or involuntary dissolution. The preferred stock and depositary preferred stock is subject to redemption at the option of the Company at a redemption price equal to 100% of the liquidation amount of the stock. Information for each outstanding series is in the table below:

| Preferred Stock | Par Value/Stated Capital Per Share | Shares Outstanding | Redemption Price Per Share |
|---|---|---|---|
| 4.40% Preferred Stock | $ 100 | 8,867 | $ 104.32 |
| 4.60% Preferred Stock | $ 100 | 8,643 | $ 107.00 |
| 4.72% Preferred Stock | $ 100 | 16,700 | $ 102.25 |
| 5.25% Preferred Stock(*) | $ 100 | 300,000 | $ 100.00 |

(*) There are 1,200,000 outstanding depositary shares, each representing one-fourth of a share of the 5.25% preferred stock.

Dividend Restrictions
The Company can only pay dividends to Southern Company out of retained earnings or paid-in-capital.

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

| Expires | | | Executable Term Loans | | Expires Within One Year | |
|---|---|---|---|---|---|---|
| 2018 | Total | Unused | One Year | Two Years | Term Out | No Term Out |
| (in millions) | (in millions) | | (in millions) | | (in millions) | |
| $100 | $100 | $100 | $— | $— | $— | $100 |

In November 2017, the Company amended certain of its one-year credit arrangements in an aggregate amount of $100 million to extend the maturity dates from 2017 to 2018.
Subject to applicable market conditions, the Company expects to renew its bank credit arrangements, as needed, prior to expiration. In connection therewith, the Company may extend the maturity dates and/or increase or decrease the lending commitments thereunder.
Most of these bank credit arrangements require payment of commitment fees based on the unused portions of the commitments or to maintain compensating balances with the banks. Commitment fees average less than 1/4 of 1% for the Company. Compensating balances are not legally restricted from withdrawal.
Most of these bank credit arrangements contain covenants that limit the Company's debt levels to 65% of total capitalization, as defined in the agreements. For purposes of these definitions, debt excludes certain hybrid securities.
A portion of the $100 million unused credit with banks is allocated to provide liquidity support to the Company's pollution control revenue bonds and its commercial paper borrowings. The amount of variable rate pollution control revenue bonds outstanding requiring liquidity support as of December 31, 2017 was $40 million. In addition, at

December 31, 2017, the Company had approximately $50 million of fixed rate revenue bonds that were remarketed from a long-term interest rate mode to an index rate mode, subsequent to December 31, 2017.
At December 31, 2017 and 2016, there was no commercial paper debt outstanding.
At December 31, 2017 and 2016, there was $4 million and $23 million, respectively, of short-term debt outstanding.

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7. COMMITMENTS
Fuel and Purchased Power Agreements
To supply a portion of the fuel requirements of its generating plants, the Company has entered into various long-term commitments for the procurement and delivery of fossil fuel which are not recognized on the balance sheets. In 2017, 2016, and 2015, the Company incurred fuel expense of $395 million, $343 million, and $443 million, respectively, the majority of which was purchased under long-term commitments. The Company expects that a substantial amount of its future fuel needs will continue to be purchased under long-term commitments.
SCS may enter into various types of wholesale energy and natural gas contracts acting as an agent for the Company and all of the other traditional electric operating companies and Southern Power. Under these agreements, each of the traditional electric operating companies and Southern Power may be jointly and severally liable. Accordingly, Southern Company has entered into keep-well agreements with the Company and each of the other traditional electric operating companies to ensure the Company will not subsidize or be responsible for any costs, losses, liabilities, or damages resulting from the inclusion of Southern Power as a contracting party under these agreements.
In addition, the Company has entered into various long-term commitments for the purchase of energy through PPAs associated with solar facilities. The energy related costs associated with PPAs are recovered through the fuel cost recovery clause.
Operating Leases
The Company has entered into operating leases with Southern Linc and third parties for the use of cellular tower space. These agreements have initial terms ranging from five to 10 years and renewal options of up to 20 years. The Company has other operating lease agreements with various terms and expiration dates. Total rent expense was $3 million, $3 million, and $5 million for 2017, 2016, and 2015, respectively. The Company includes any step rents, fixed escalations, lease concessions, and reasonably assured renewal periods in its computation of minimum lease payments.
Estimated minimum lease payments under operating leases at December 31, 2017 were as follows:

| | Affiliate Operating Lease[(a)] | Non-Affiliate Operating Lease[(b)] | Total |
|---|---|---|---|
| | (in millions) | | |
| 2018 | $2 | $ 1 | $ 3 |
| 2019 | 2 | 1 | 3 |
| 2020 | 2 | 1 | 3 |
| 2021 | 2 | — | 2 |
| 2022 | 2 | — | 2 |
| 2023 and thereafter | 7 | — | 7 |
| Total | $17 | $ 3 | $ 20 |

(a) Includes operating leases with affiliates primarily related to cellular towers.
(b) Primarily includes railcar and fuel handling equipment leases for Plant Daniel.
In addition to the above rental commitments, the Company entered into operating lease agreements for aluminum railcars for the transportation of coal at Plant Daniel, which is jointly owned with Gulf Power. The Company has the option to purchase the railcars at the greater of lease termination value or fair market value or to renew the leases at the end of the lease term. The Company also has separate lease agreements for other railcars that do not contain a purchase option.
The Company's 50% share of the lease costs, charged to fuel stock and recovered through the fuel cost recovery clause, was $1 million in 2017, $2 million in 2016, and $2 million in 2015.

In addition to railcar leases, the Company has other operating leases for fuel handling equipment at Plant Daniel. The Company's 50% share of the leases for fuel handling was charged to fuel handling expense annually from 2015 through 2017; however, those amounts were immaterial for the reporting period.

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8. STOCK COMPENSATION
Stock-Based Compensation
Stock-based compensation primarily in the form of Southern Company performance share units and restricted stock units may be granted through the Omnibus Incentive Compensation Plan to a large segment of the Company's employees ranging from line management to executives. 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 180 current and former employees participating in the stock option, performance share unit, and restricted stock unit programs.
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. The 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.
For the years ended December 31, 2017, 2016, and 2015, employees of the Company were granted performance share units of 30,933, 62,435, and 53,909, respectively. The weighted average grant-date fair value of TSR-based performance share units granted during 2017, 2016, and 2015, determined using a Monte Carlo simulation model to estimate the TSR of Southern Company's stock among the industry peers over the performance period, was $49.24,

$45.17, and $46.41, respectively. The weighted average grant-date fair value of both EPS-based and ROE-based performance share units granted during 2017, 2016, and 2015 was $49.22, $48.84, and $47.77, respectively.
For the years ended December 31, 2017, 2016, and 2015, total compensation cost for performance share units recognized in income was $2 million, $4 million, and $4 million, respectively, with the related tax benefit also recognized in income of $1 million, $1 million, and $2 million, respectively. The compensation cost related to the grant of Southern Company performance share units to the Company's employees is recognized in the Company's financial statements with a corresponding credit to equity, representing a capital contribution from Southern Company. As of December 31, 2017, total unrecognized compensation cost related to performance share award units was immaterial.

NOTES (continued)
Mississippi Power Company 2017 Annual Report

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.
For the year ended December 31, 2017, employees of the Company were granted 13,260 restricted stock units. The weighted average grant-date fair value of restricted stock units granted during 2017 was $49.22.
For the year ended December 31, 2017, total compensation cost for restricted stock units and the related tax benefit also recognized in income was immaterial. As of December 31, 2017, total unrecognized compensation cost related to restricted stock units was immaterial.
Stock Options
In 2015, Southern Company discontinued the granting of stock options. Stock options expire no later than 10 years after the grant date and the latest possible exercise will occur no later than November 2024.
The compensation cost related to the grant of Southern Company stock options to the Company's employees is recognized in the Company's financial statements with a corresponding credit to equity, representing a capital contribution from Southern Company. Compensation cost and related tax benefits recognized in the Company's financial statements were not material for any year presented. As of December 31, 2017, all compensation cost related to stock option awards has been recognized.
The total intrinsic value of options exercised during the years ended December 31, 2017, 2016, and 2015 was $2 million, $4 million, and $3 million, respectively. No cash proceeds are received by the Company upon the exercise of stock options. The actual tax benefit realized by the Company for the tax deductions from stock option exercises totaled $1 million, $2 million, and $1 million for the years ended December 31, 2017, 2016, and 2015, respectively. Prior to the adoption of ASU 2016-09 in 2016, the excess tax benefits related to the exercise of stock options were recognized in the Company's financial statements with a credit to equity. Upon the adoption of ASU 2016-09, beginning in 2016, all tax benefits related to the exercise of stock options are recognized in income. As of December 31, 2017, the aggregate intrinsic value for the options outstanding and exercisable was $4 million.
9. FAIR VALUE MEASUREMENTS
Fair value measurements are based on inputs of observable and unobservable market data that a market participant would use in pricing the asset or liability. The use of observable inputs is maximized where available and the use of unobservable inputs is minimized for fair value measurement and reflects a three-tier fair value hierarchy that prioritizes inputs to valuation techniques used for fair value measurement.

- Level 1 consists of observable market data in an active market for identical assets or liabilities.
- Level 2 consists of observable market data, other than that included in Level 1, that is either directly or indirectly observable.
- Level 3 consists of unobservable market data. The input may reflect the assumptions of the Company of what a market participant would use in pricing an asset or liability. If there is little available market data, then the Company's own assumptions are the best available information.

In the case of multiple inputs being used in a fair value measurement, the lowest level input that is significant to the fair value measurement represents the level in the fair value hierarchy in which the fair value measurement is reported.

NOTES (continued)
Mississippi Power Company 2017 Annual Report

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 | | | |
|---|---|---|---|---|
| | Quoted Prices in Active Markets for Identical Assets | Significant Other Observable Inputs | Significant Unobservable Inputs | |
| As of December 31, 2017: | (Level 1) | (Level 2) | (Level 3) | Total |
| | (in millions) | | | |
| Assets: | | | | |
| Energy-related derivatives | $— | $ 2 | $ — | $2 |
| Interest rate derivatives | — | 1 | — | 1 |
| Cash equivalents | 224 | — | — | 224 |
| Total | $224 | $ 3 | $ — | $227 |
| Liabilities: | | | | |
| Energy-related derivatives | $— | $ 9 | $ — | $9 |

As of December 31, 2016, assets and liabilities measured at fair value on a recurring basis during the period, together with their associated level of the fair value hierarchy, were as follows:

| | Fair Value Measurements Using | | | |
|---|---|---|---|---|
| | Quoted Prices in Active Markets for Identical Assets | Significant Other Observable Inputs | Significant Unobservable Inputs | |
| As of December 31, 2016: | (Level 1) | (Level 2) | (Level 3) | Total |
| | (in millions) | | | |
| Assets: | | | | |
| Energy-related derivatives | $— | $ 3 | $ — | $3 |
| Interest rate derivatives | — | 3 | — | 3 |
| Cash equivalents | 206 | — | — | 206 |
| Total | $206 | $ 6 | $ — | $212 |
| Liabilities: | | | | |
| Energy-related derivatives | $— | $ 10 | $ — | $10 |

Valuation Methodologies

The energy-related derivatives primarily consist of over-the-counter financial products for natural gas and physical power products, including, from time to time, basis swaps. These are standard products used within the energy industry and are valued using the market approach. The inputs used are mainly from observable market sources, such as forward natural gas prices, power prices, implied volatility, and overnight index swap interest rates. See Note 10 for additional information on how these derivatives are used.

NOTES (continued)
Mississippi Power Company 2017 Annual Report

As of December 31, 2017 and 2016, other financial instruments for which the carrying amount did not equal fair value were as follows:

| | Carrying Amount | Fair Value |
|---|---|---|
| | (in millions) | |
| Long-term debt: | | |
| 2017 | $2,086 | $2,076 |
| 2016 | $2,979 | $2,922 |

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 offered to the Company.

10. DERIVATIVES

The Company is exposed to market risks, primarily commodity price risk and interest rate risk. To manage the volatility attributable to these exposures, the Company nets its exposures, where possible, to take advantage of natural offsets and enters into various derivative transactions for the remaining exposures pursuant to the Company's policies in areas such as counterparty exposure and risk management practices. The Company's policy is that derivatives are to be used primarily for hedging purposes and mandates strict adherence to all applicable risk management policies. Derivative positions are monitored using techniques including, but not limited to, market valuation, value at risk, stress testing, and sensitivity analysis. Derivative instruments are recognized at fair value in the balance sheets as either assets or liabilities and are presented on a net basis. See Note 9 for additional information. In the statements of cash flows, the cash impacts of settled energy-related and interest rate derivatives are recorded as operating activities.

Energy-Related Derivatives

The Company enters into energy-related derivatives to hedge exposures to electricity, gas, and other fuel price changes. However, due to cost-based rate regulations and other various cost recovery mechanisms, the Company has limited exposure to market volatility in energy-related commodity prices. The Company manages fuel-hedging programs, implemented per the guidelines of the Mississippi PSC, through the use of financial derivative contracts, which is expected to continue to mitigate price volatility.

Energy-related derivative contracts are accounted for under one of the following methods:

- Regulatory Hedges – Energy-related derivative contracts which are designated as regulatory hedges relate primarily to the Company's fuel-hedging programs, where gains and losses are initially recorded as regulatory liabilities and assets, respectively, and then are included in fuel expense as the underlying fuel is used in operations and ultimately recovered through the respective fuel cost recovery clauses.
- 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 operations as incurred.

Some energy-related derivative contracts require physical delivery as opposed to financial settlement, and this type of derivative is both common and prevalent within the electric industry. When an energy-related derivative contract is settled physically, any cumulative unrealized gain or loss is reversed and the contract price is recognized in the respective line item representing the actual price of the underlying goods being delivered.

At December 31, 2017, the net volume of energy-related derivative contracts for natural gas positions totaled 53 million mmBtu for the Company, with the longest hedge date of 2021 over which the Company is hedging its exposure to the variability in future cash flows for forecasted transactions.

In addition to the volume discussed above, the Company enters into physical natural gas supply contracts that provide the option to sell back excess gas due to operational constraints. The maximum expected volume of natural gas subject to such a feature is 4 million mmBtu.

Interest Rate Derivatives

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

NOTES (continued)
Mississippi Power Company 2017 Annual Report

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 |

The estimated pre-tax losses that will be reclassified from accumulated OCI to interest expense for the next 12-month period ending December 31, 2018 are $0.5 million. The Company has deferred gains and losses that are expected to be amortized into earnings through 2022.

Derivative Financial Statement Presentation and Amounts

The Company enters into energy-related and interest rate derivative contracts that may contain certain provisions that permit intra-contract netting of derivative receivables and payables for routine billing and offsets related to events of default and settlements. 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 counterparties.

At December 31, 2017 and 2016, the fair value of energy-related derivatives and interest rate derivatives was reflected on the balance sheets as follows:

| Derivative Category and Balance Sheet Location | 2017 Assets | 2017 Liabilities | 2016 Assets | 2016 Liabilities |
|---|---|---|---|---|
| | (in millions) | | | |
| Derivatives designated as hedging instruments for regulatory purposes | | | | |
| Energy-related derivatives: | | | | |
| Other current assets/Other current liabilities | $1 | $ 6 | $2 | $ 6 |
| Other deferred charges and assets/Other deferred credits and liabilities | 1 | 3 | 2 | 5 |
| Total derivatives designated as hedging instruments for regulatory purposes | $2 | $ 9 | $4 | $ 11 |
| Derivatives designated as hedging instruments in cash flow and fair value hedges | | | | |
| Interest rate derivatives: | | | | |
| Other current assets/Other current liabilities | $1 | $ — | $2 | $ — |
| Other deferred charges and assets/Other deferred credits and liabilities | — | — | 1 | — |
| Total derivatives designated as hedging instruments in cash flow and fair value hedges | $1 | $ — | $3 | $ — |
| Gross amounts recognized | $3 | $ 9 | $7 | $ 11 |
| Gross amounts offset | $(2) | $ (2) | $(3) | $ (3) |
| Net amounts recognized in the Balance Sheets | $1 | $ 7 | $4 | $ 8 |

Energy-related derivatives not designated as hedging instruments were immaterial for 2017 and 2016.

NOTES (continued)
Mississippi Power Company 2017 Annual Report

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:

| Derivative Category | Unrealized Losses Balance Sheet Location | 2017 | 2016 | Unrealized Gains Balance Sheet Location | 2017 | 2016 |
|---|---|---|---|---|---|---|
| | | (in millions) | | | (in millions) | |
| Energy-related derivatives: | Other regulatory assets, current | $(5) | $(5) | Other current liabilities | $ — | $ 1 |
| | Other regulatory assets, deferred | (2) | (3) | Other regulatory liabilities, deferred | — | — |
| Total energy-related derivative gains (losses) | | $(7) | $(8) | | $ — | $ 1 |

For all years presented, the pre-tax effects of energy-related derivatives not designated as hedging instruments on the statements of operations were immaterial.

For the years ended December 31, 2017, 2016, and 2015, the pre-tax effects of derivatives designated as cash flow hedging instruments on the statements of operations 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 affiliated companies. At December 31, 2017, the Company had no collateral posted with its derivative counterparties.

At December 31, 2017, the fair value of derivative liabilities with contingent features was $1 million. However, because of joint and several liability features underlying these derivatives, the maximum potential collateral requirements arising from the credit-risk-related contingent features, at a rating below BBB- and/or Baa3, were $12 million, and include certain agreements that could require collateral in the event that one or more Southern Company system power pool participants has a credit rating change to below investment grade.

Generally, collateral may be provided by a Southern Company guaranty, letter of credit, or cash. If collateral is required, fair value amounts recognized for the right to reclaim cash collateral or the obligation to return cash collateral are not offset against fair value amounts recognized for derivatives executed with the same counterparty.

The Company is exposed to losses related to financial instruments in the event of counterparties' nonperformance. The Company only enters into agreements and material transactions with counterparties that have investment grade credit ratings by Moody's and S&P or with counterparties who have posted collateral to cover potential credit exposure. The Company has also established risk management policies and controls to determine and monitor the creditworthiness of counterparties in order to mitigate the Company's exposure to counterparty credit risk. Therefore, the Company does not anticipate a material adverse effect on the financial statements as a result of counterparty nonperformance.

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NOTES (continued)
Mississippi Power Company 2017 Annual Report

11. QUARTERLY FINANCIAL INFORMATION (UNAUDITED)

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

| Quarter Ended | Operating Revenues | Operating Income (Loss) | Net Income (Loss) After Dividends on Preferred Stock |
|---|---|---|---|
| | (in millions) | | |
| March 2017 | $272 | $ (62) | $ (20) |
| June 2017 | 303 | (2,954) | (2,054) |
| September 2017 | 341 | 51 | 40 |
| December 2017 | 271 | (177) | (556) |
| | | | |
| March 2016 | $257 | $ (10) | $ 11 |
| June 2016 | 277 | (28) | 2 |
| September 2016 | 352 | 9 | 26 |
| December 2016 | 277 | (166) | (89) |

As a result of the revisions to the cost estimate for the Kemper IGCC and its June 2017 suspension, the Company 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 Tax Reform Legislation, the Company recorded total income tax expense of $372 million in the fourth quarter 2017. See Note 5 for additional information.

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

SELECTED FINANCIAL AND OPERATING DATA 2013-2017
Mississippi Power Company 2017 Annual Report

| | 2017 | 2016 | 2015 | 2014 | 2013 |
|---|---|---|---|---|---|
| Operating Revenues (in millions) | $1,187 | $1,163 | $1,138 | $1,243 | $1,145 |
| Net Income (Loss) After Dividends on Preferred Stock (in millions)[a] | $(2,590) | $(50) | $(8) | $(329) | $(477) |
| Cash Dividends on Common Stock (in millions) | $— | $— | $— | $— | $72 |
| Return on Average Common Equity (percent)[a] | (120.43) | (1.87) | (0.34) | (15.43) | (24.28) |
| Total Assets (in millions)[b][c] | $4,866 | $8,235 | $7,840 | $6,642 | $5,822 |
| Gross Property Additions (in millions) | $536 | $946 | $972 | $1,389 | $1,773 |
| Capitalization (in millions): | | | | | |
| Common stock equity | $1,358 | $2,943 | $2,359 | $2,084 | $2,177 |
| Redeemable preferred stock | 33 | 33 | 33 | 33 | 33 |
| Long-term debt[b] | 1,097 | 2,424 | 1,886 | 1,621 | 2,157 |
| Total (excluding amounts due within one year) | $2,488 | $5,400 | $4,278 | $3,738 | $4,367 |
| Capitalization Ratios (percent): | | | | | |
| Common stock equity | 54.6 | 54.5 | 55.1 | 55.8 | 49.9 |
| Redeemable preferred stock | 1.3 | 0.6 | 0.8 | 0.9 | 0.7 |
| Long-term debt[b] | 44.1 | 44.9 | 44.1 | 43.3 | 49.4 |
| Total (excluding amounts due within one year) | 100.0 | 100.0 | 100.0 | 100.0 | 100.0 |
| Customers (year-end): | | | | | |
| Residential | 153,115 | 153,172 | 153,158 | 152,453 | 152,585 |
| Commercial | 33,992 | 33,783 | 33,663 | 33,496 | 33,250 |
| Industrial | 452 | 451 | 467 | 482 | 480 |
| Other | 173 | 175 | 175 | 175 | 175 |
| Total | 187,732 | 187,581 | 187,463 | 186,606 | 186,490 |
| Employees (year-end) | 1,242 | 1,484 | 1,478 | 1,478 | 1,344 |

(a) A significant loss to income was recorded by the Company 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.

(b) A reclassification of debt issuance costs from Total Assets to Long-term debt of $9 million and $11 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 $105 million and $16 million is reflected for years 2014 and 2013, respectively, in accordance with new accounting standards adopted in 2015 and applied retrospectively.

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SELECTED FINANCIAL AND OPERATING DATA 2013-2017 (continued)
Mississippi Power Company 2017 Annual Report

| | 2017 | 2016 | 2015 | 2014 | 2013 |
|---|---|---|---|---|---|
| Operating Revenues (in millions): | | | | | |
| Residential | $257 | $260 | $238 | $239 | $242 |
| Commercial | 285 | 279 | 256 | 257 | 266 |
| Industrial | 321 | 313 | 287 | 291 | 289 |
| Other | (9) | 7 | (5) | 8 | 2 |
| Total retail | 854 | 859 | 776 | 795 | 799 |
| Wholesale — non-affiliates | 259 | 261 | 270 | 323 | 294 |
| Wholesale — affiliates | 56 | 26 | 76 | 107 | 35 |
| Total revenues from sales of electricity | 1,169 | 1,146 | 1,122 | 1,225 | 1,128 |
| Other revenues | 18 | 17 | 16 | 18 | 17 |
| Total | $1,187 | $1,163 | $1,138 | $1,243 | $1,145 |
| Kilowatt-Hour Sales (in millions): | | | | | |
| Residential | 1,944 | 2,051 | 2,025 | 2,126 | 2,088 |
| Commercial | 2,764 | 2,842 | 2,806 | 2,860 | 2,865 |
| Industrial | 4,841 | 4,906 | 4,958 | 4,943 | 4,739 |
| Other | 39 | 39 | 40 | 40 | 40 |
| Total retail | 9,588 | 9,838 | 9,829 | 9,969 | 9,732 |
| Wholesale — non-affiliates | 3,672 | 3,920 | 3,852 | 4,191 | 3,929 |
| Wholesale — affiliates | 2,024 | 1,108 | 2,807 | 2,900 | 931 |
| Total | 15,284 | 14,866 | 16,488 | 17,060 | 14,592 |
| Average Revenue Per Kilowatt-Hour (cents)(*): | | | | | |
| Residential | 13.22 | 12.68 | 11.75 | 11.26 | 11.59 |
| Commercial | 10.31 | 9.82 | 9.12 | 8.99 | 9.27 |
| Industrial | 6.63 | 6.38 | 5.79 | 5.89 | 6.10 |
| Total retail | 8.91 | 8.73 | 7.90 | 7.97 | 8.21 |
| Wholesale | 5.53 | 5.71 | 5.20 | 6.06 | 6.76 |
| Total sales | 7.65 | 7.71 | 6.80 | 7.18 | 7.73 |
| Residential Average Annual Kilowatt-Hour Use Per Customer | 12,692 | 13,383 | 13,242 | 13,934 | 13,680 |
| Residential Average Annual Revenue Per Customer | $1,680 | $1,697 | $1,556 | $1,568 | $1,585 |
| Plant Nameplate Capacity Ratings (year-end) (megawatts) | 3,628 | 3,481 | 3,561 | 3,867 | 3,088 |
| Maximum Peak-Hour Demand (megawatts): | | | | | |
| Winter | 2,390 | 2,195 | 2,548 | 2,618 | 2,083 |
| Summer | 2,322 | 2,384 | 2,403 | 2,345 | 2,352 |
| Annual Load Factor (percent) | 63.1 | 64.0 | 60.6 | 59.4 | 64.7 |
| Plant Availability Fossil-Steam (percent) | 89.1 | 91.4 | 90.6 | 87.6 | 89.3 |
| Source of Energy Supply (percent): | | | | | |
| Coal | 7.5 | 8.0 | 16.5 | 39.7 | 32.7 |
| Oil and gas | 88.0 | 84.9 | 81.6 | 55.3 | 57.1 |
| Purchased power — | | | | | |
| From non-affiliates | 0.5 | (0.3) | 0.4 | 1.4 | 2.0 |
| From affiliates | 4.0 | 7.4 | 1.5 | 3.6 | 8.2 |
| Total | 100.0 | 100.0 | 100.0 | 100.0 | 100.0 |

(*)

The average revenue per kilowatt-hour (cents) is based on booked operating revenues and will not match billed revenue per kilowatt-hour.

SOUTHERN POWER COMPANY
FINANCIAL SECTION

MANAGEMENT'S REPORT ON INTERNAL CONTROL OVER FINANCIAL REPORTING
Southern Power Company and Subsidiary Companies 2017 Annual Report
The management of Southern Power Company (the Company) is responsible for establishing and maintaining an adequate system of internal control over financial reporting as required by the Sarbanes-Oxley Act of 2002 and as defined in Exchange Act Rule 13a-15(f). A control system can provide only reasonable, not absolute, assurance that the objectives of the control system are met.
Under management's supervision, an evaluation of the design and effectiveness of the Company's internal control over financial reporting was conducted based on the framework in Internal Control—Integrated Framework (2013) issued by the Committee of Sponsoring Organizations of the Treadway Commission. Based on this evaluation, management concluded that the Company's internal control over financial reporting was effective as of December 31, 2017.

/s/ Joseph A. Miller
Joseph A. Miller
Chairman, President, and Chief Executive Officer

/s/ William C. Grantham
William C. Grantham
Senior Vice President, Chief Financial Officer, and Treasurer
February 20, 2018

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the stockholder and the Board of Directors of Southern Power Company and Subsidiary Companies

Opinion on the Financial Statements

We have audited the accompanying consolidated balance sheets of Southern Power Company and Subsidiary Companies (the Company) (a wholly-owned subsidiary of The Southern 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"). In our opinion, the financial statements (pages II-508 to II-542) 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.

Basis for Opinion

These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on the Company's financial statements 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 audit to obtain reasonable assurance about whether the financial statements are free of material misstatement, whether due to error or fraud. The Company is not required to have, nor were we engaged to perform, an audit of its internal control over financial reporting. As part of our audits, we are required to obtain an understanding of internal control over financial reporting but not for the purpose of expressing an opinion on the effectiveness of the Company's internal control over financial reporting. Accordingly, we express no such opinion. Our audits included performing procedures to assess the risks of material misstatement of the financial statements, whether due to error or fraud, and performing procedures that 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. We believe that our audits provide a reasonable basis for our opinion.

/s/ Deloitte & Touche LLP

Atlanta, Georgia

February 20, 2018

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

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DEFINITIONS

| Term | Meaning |
|---|---|
| Alabama Power | Alabama Power Company |
| AOCI | Accumulated other comprehensive income |
| ASC | Accounting Standards Codification |
| ASU | Accounting Standards Update |
| $CO_2$ | Carbon dioxide |
| COD | Commercial operation date |
| CWIP | Construction work in progress |
| EPA | U.S. Environmental Protection Agency |
| FASB | Financial Accounting Standards Board |
| FERC | Federal Energy Regulatory Commission |
| GAAP | U.S. generally accepted accounting principles |
| Georgia Power | Georgia Power Company |
| Gulf Power | Gulf Power Company |
| IRS | Internal Revenue Service |
| ITC | Investment tax credit |
| KWH | Kilowatt-hour |
| LTSA | Long-term service agreement |
| Mississippi Power | Mississippi Power Company |
| mmBtu | Million British thermal units |
| Moody's | Moody's Investors Service, Inc. |
| MW | Megawatt |
| MWH | Megawatt hour |
| $NO_X$ | Nitrogen oxide |
| OCI | Other comprehensive income |
| power pool | The operating arrangement whereby the integrated generating resources of the traditional electric operating companies and Southern Power (excluding subsidiaries) are subject to joint commitment and dispatch in order to serve their combined load obligations |
| PPA | Power purchase agreements, as well as contracts for differences that provide the owner of a renewable facility a certain fixed price for the electricity sold to the grid |
| PTC | Production tax credit |
| 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 |
| $SO_2$ | Sulfur dioxide |
| Southern Company | The Southern Company |
| Southern Company Gas | Southern Company Gas and its subsidiaries |
| Southern Company system | Southern Company, the traditional electric operating companies, Southern Power Company, Southern Company Gas (as of July 1, 2016), Southern Electric Generating Company, Southern Nuclear, SCS, Southern Linc, PowerSecure, Inc. (as of May 9, 2016), and other subsidiaries |
| Southern Linc | Southern Communications Services, Inc. |
| Southern Nuclear | Southern Nuclear Operating Company, Inc. |
| 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 |
| traditional electric operating companies | Alabama Power, Georgia Power, Gulf Power, and Mississippi Power |

MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS
Southern Power Company and Subsidiary Companies 2017 Annual Report
OVERVIEW
Business Activities
Southern Power Company and its subsidiaries (the Company) develop, construct, acquire, own, and manage power generation assets, including renewable energy projects, and sell electricity at market-based rates in the wholesale market. The Company continually seeks opportunities to execute its strategy 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, the Company has committed to the construction or acquisition of new generating capacity only after entering into or assuming long-term PPAs for the new facilities.
During 2017, the Company acquired or commenced construction of approximately 424 MWs of additional wind facilities and completed construction of, and placed in service, approximately 222 MWs of solar facilities. In addition, the Company continued development of its portfolio of wind projects and continued expansion of the 345-MW Mankato natural gas facility. Subsequent to December 31, 2017, the Company acquired Gaskell West 1, which is an approximately 20-MW solar facility. See FUTURE EARNINGS POTENTIAL – "Acquisitions" and "Construction Projects" herein for additional information.
As of December 31, 2017, the Company's generation fleet totaled 12,940 MWs of nameplate capacity in commercial operation (including 5,152 MWs owned by its subsidiaries). The average remaining duration of the Company's total portfolio of wholesale contracts is approximately 15 years, which reduces remarketing risk for the Company. With the inclusion of the PPAs and investments associated with renewable and natural gas facilities currently under construction and acquired subsequent to December 31, 2017, the Company has an average investment coverage ratio of 91% through 2022 and 89% through 2027.
The Company is pursuing the sale of a 33% equity interest in a newly-formed holding company that owns substantially all of the Company's solar assets, which, if successful, is expected to close in the middle of 2018. The ultimate outcome of this matter cannot be determined at this time.
The Company's future earnings will depend on the parameters of the wholesale market and the efficient operation of its wholesale generating assets, as well as the Company's ability to execute its growth strategy and to develop and construct generating facilities. In addition, the Company's earnings may be impacted by the availability of federal and state solar ITCs and wind PTCs on its renewable energy projects, which could be impacted by current or future potential tax reform legislation. See FUTURE EARNINGS POTENTIAL – "Acquisitions," "Construction Projects," and "Income Tax Matters" herein for additional information.
Effective in December 2017, 538 employees transferred from SCS to the Company. The Company became obligated for related employee costs including pension, other postretirement benefits, and stock-based compensation and has recognized the respective balance sheet assets and liabilities, including AOCI impacts, in its balance sheet at December 31, 2017. Prior to the transfer of employees, the Company's agreements with SCS provided for employee services rendered at amounts in compliance with FERC regulations.
To evaluate operating results and to ensure the Company's ability to meet its contractual commitments to customers, the Company continues to focus on several key performance indicators, including, but not limited to, peak season equivalent forced outage rate, contract availability, and net income.
See RESULTS OF OPERATIONS herein for information on the Company's financial performance.
Earnings
The Company's 2017 net income was $1.1 billion, a $733 million increase from 2016, primarily attributable to $743 million related to the Tax Reform Legislation. Also contributing to the change were increases in operating expenses and interest expense related to the Company's growth strategy and continuous construction program, largely offset by increased renewable energy sales.

The Company's 2016 net income was $338 million, a $123 million, or 57%, increase from 2015. The increase was primarily due to increased federal income tax benefits from solar ITCs and wind PTCs and increased renewable energy sales, partially offset by increases in depreciation, operations and maintenance expenses, and interest expense from debt issuances, primarily related to new solar and wind facilities.

MANAGEMENT'S DISCUSSION AND ANALYSIS (continued)
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Benefits from solar ITCs, related to the Company's acquisition and construction of new facilities, and wind PTCs, related to wind generation, significantly impacted the Company's net income in 2017 and 2016. The Company's net income in 2015 was also significantly impacted by solar ITCs. See Note 5 to the financial statements under "Effective Tax Rate" for additional information.

RESULTS OF OPERATIONS

A condensed statement of income follows:

| | Amount | Increase (Decrease) from Prior Year | |
|---|---|---|---|
| | 2017 | 2017 | 2016 |
| | (in millions) | | |
| Operating revenues | $2,075 | $ 498 | $ 187 |
| Fuel | 621 | 165 | 15 |
| Purchased power | 149 | 47 | 9 |
| Other operations and maintenance | 386 | 32 | 94 |
| Depreciation and amortization | 503 | 151 | 104 |
| Taxes other than income taxes | 48 | 25 | 1 |
| Total operating expenses | 1,707 | 420 | 223 |
| Operating income | 368 | 78 | (36) |
| Interest expense, net of amounts capitalized | 191 | 74 | 40 |
| Other income (expense), net | 1 | (5) | 5 |
| Income taxes (benefit) | (939) | (744) | (216) |
| Net income | 1,117 | 743 | 145 |
| Less: Net income attributable to noncontrolling interests | 46 | 10 | 22 |
| Net income attributable to the Company | $1,071 | $ 733 | $ 123 |

Operating Revenues

Total operating revenues include PPA capacity revenues, which are derived primarily from long-term contracts involving natural gas and biomass generating facilities, and PPA energy revenues from the Company's generation facilities. To the extent the Company has capacity not contracted under a PPA, it may sell power into the wholesale market and, to the extent the generation assets are part of the Intercompany Interchange Contract (IIC), as approved by the FERC, it may sell power into the power pool.

Natural Gas and Biomass Capacity and Energy Revenue

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 is generally sold at variable cost or is indexed to published natural gas indices. Energy revenues will vary depending on the energy demand of the Company's customers and their generation capacity, as well as the market prices of wholesale energy compared to the cost of the Company's energy. Energy revenues also include fees for support services, fuel storage, and unit start charges. Increases and decreases in energy revenues under PPAs that are driven by fuel or purchased power prices are accompanied by an increase or decrease in fuel and purchased power costs and do not have a significant impact on net income.

Solar and Wind Energy Revenue

The Company's energy sales from solar and wind generating facilities are predominantly through long-term PPAs that do not have a capacity charge. Customers either purchase the energy output of a dedicated renewable facility through an energy charge or pay a fixed price related to the energy sold to the grid. 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.

See FUTURE EARNINGS POTENTIAL – "Power Sales Agreements" herein for additional information regarding the Company's PPAs.

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Southern Power Company and Subsidiary Companies 2017 Annual Report

Details of the Company's operating revenues were as follows:

| | 2017 | 2016 | 2015 |
|---|---|---|---|
| | | (in millions) | |
| PPA capacity revenues | $599 | $ 541 | $569 |
| PPA energy revenues | 970 | 694 | 560 |
| Total PPA revenues | 1,569 | 1,235 | 1,129 |
| Non-PPA revenues | 494 | 330 | 252 |
| Other revenues | 12 | 12 | 9 |
| Total operating revenues | $2,075 | $ 1,577 | $1,390 |

Operating revenues for 2017 were $2.1 billion, reflecting a $498 million, or 32%, increase from 2016. The increase in operating revenues was primarily due to the following:

- PPA capacity revenues increased $58 million, or 11%, primarily due to additional customer capacity requirements, and a new PPA related to the Mankato natural gas facility acquired in late 2016.
- PPA energy revenues increased $276 million, or 40%, primarily due to a $213 million increase in renewable energy sales arising from new solar and wind facilities and a $50 million increase in sales from existing natural gas PPAs primarily due to an $85 million increase in the average cost of fuel, partially offset by a $35 million decrease in the volume of KWHs sold primarily due to reduced customer load.
- Non-PPA revenues increased $164 million, or 50%, primarily due to a $156 million increase in the volume of KWHs sold primarily from uncovered natural gas capacity through short-term opportunity sales, as well as an $8 million increase in the price of energy in the wholesale markets.

Operating revenues for 2016 were $1.6 billion, reflecting a $187 million, or 13%, increase from 2015. The increase in operating revenues was primarily due to the following:

- PPA capacity revenues decreased $28 million as a result of a $44 million decrease in non-affiliate capacity revenues primarily as a result of PPA expirations and subsequent generation capacity remarketing into the short-term markets, partially offset by a $16 million increase in affiliate capacity revenues due to new PPAs.
- PPA energy revenues increased $134 million primarily due to a $170 million increase in renewable energy sales arising from new solar and wind facilities, partially offset by a decrease of $36 million in fuel revenues related to natural gas PPAs. Overall, total KWH sales under PPAs increased 7% in 2016 when compared to 2015.
- Non-PPA revenues increased $78 million primarily due to a 23% increase in KWH sales. Underlying this increase was a $113 million increase in short-term sales to non-affiliates as a result of remarketing generation capacity from expired PPAs, partially offset by a $35 million decrease in power pool sales primarily associated with a reduction in capacity available for sale.

Fuel and Purchased Power Expenses

Fuel costs constitute one of the largest expenses for the Company. In addition, the Company purchases a portion of its electricity needs from the wholesale market including the power pool. Details of the Company's generation and purchased power were as follows:

| | Total KWHs 2017 | Total KWH % Change | Total KWHs 2016 | Total KWH % Change |
|---|---|---|---|---|
| | (in billions of KWHs) | | | |
| Generation | 44 | | 37 | |
| Purchased power | 5 | | 3 | |
| Total generation and purchased power | 49 | 23% | 40 | 14% |
| Total generation and purchased power, excluding solar, wind, and tolling agreements | 28 | 22% | 23 | 10% |

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The Company's PPAs for natural gas and biomass generation generally provide that the purchasers are responsible for either procuring the fuel (tolling agreements) or reimbursing the Company for substantially all of the cost of fuel relating to the energy delivered under such PPAs. Consequently, changes in such fuel costs are generally accompanied by a corresponding change in related fuel revenues and do not have a significant impact on net income. The Company is responsible for the cost of fuel for generating units that are not covered under PPAs. Power from these generating units is sold into the wholesale market or into the power pool for capacity owned directly by the Company.
Purchased power expenses will vary depending on demand, availability, and the cost of generating resources throughout the Southern Company system and other contract resources. Load requirements are submitted to the power pool on an hourly basis and are fulfilled with the lowest cost alternative, whether that is generation owned by the Company, an affiliate company, or external parties. Such purchased power costs are generally recovered through PPA revenues.
Details of the Company's fuel and purchased power expenses were as follows:

| | 2017 | 2016 | 2015 |
|---|---|---|---|
| | | (in millions) | |
| Fuel | $621 | $ 456 | $441 |
| Purchased power | 149 | 102 | 93 |
| Total fuel and purchased power expenses | $770 | $ 558 | $534 |

In 2017, total fuel and purchased power expenses increased $212 million, or 38%, compared to 2016. Fuel expense increased $165 million, or 36%, primarily due to an $83 million increase associated with the volume of KWHs generated and an $82 million increase associated with the average cost of natural gas per KWH generated. Purchased power expense increased $47 million, or 46%, primarily due to a $37 million increase associated with the volume of KWHs purchased and an $11 million increase associated with the average cost of purchased power.
In 2016, total fuel and purchased power expenses increased $24 million, or 4%, compared to 2015. Fuel expense increased $15 million, or 3%, primarily due to a $22 million increase associated with the volume of KWHs generated, partially offset by a $7 million decrease associated with the average cost of natural gas per KWH generated. Purchased power expense increased $9 million, or 10%, primarily due to a $53 million increase associated with the volume of KWHs purchased, partially offset by a $28 million decrease associated with the average cost of purchased power and a $16 million decrease associated with a PPA expiration.
Other Operations and Maintenance Expenses
In 2017, other operations and maintenance expenses increased $32 million, or 9%, compared to 2016. The increase was primarily due to increases of $56 million associated with new facilities, $21 million in business development and support expenses, and $6 million in employee compensation, all associated with the Company's overall growth. These increases were partially offset by decreases of $35 million associated with scheduled outage and maintenance expenses and $15 million in non-outage operations and maintenance expenses.
In 2016, other operations and maintenance expenses increased $94 million, or 36%, compared to 2015. The increase was primarily due to increases of $35 million associated with new plants placed in service in 2015 and 2016, $25 million associated with scheduled outage and maintenance expenses, and $21 million in business development and support expenses and $13 million in employee compensation all primarily associated with the Company's overall growth.
Depreciation and Amortization
In 2017, depreciation and amortization increased $151 million, or 43%, compared to 2016. In 2016, depreciation and amortization increased $104 million, or 42%, compared to 2015. These increases were primarily due to additional depreciation related to new solar, wind, and natural gas facilities placed in service. See Note 1 to the financial statements under "Depreciation" for additional information.
Taxes Other Than Income Taxes

In 2017, taxes other than income taxes were $48 million compared to $23 million in 2016. In 2016, taxes other than income taxes increased $1 million, or 5%, compared to 2015. The increases were primarily due to additional property taxes due to new facilities.

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Interest Expense, Net of Amounts Capitalized

In 2017, interest expense, net of amounts capitalized increased $74 million, or 63%, compared to 2016. The increase was primarily due to an increase of $44 million in interest expense related to an increase in average outstanding long-term debt, primarily to fund the Company's growth strategy and continuous construction program, as well as a $30 million decrease in capitalized interest associated with completing construction of and placing in service solar facilities.

In 2016, interest expense, net of amounts capitalized increased $40 million, or 52%, compared to 2015. The increase was primarily due to an increase of $66 million in interest expense related to additional debt issued during 2016 primarily to fund the Company's growth strategy and continuous construction program, partially offset by a $26 million increase in capitalized interest associated with the construction of solar facilities.

Other Income (Expense), Net

In 2017, other income (expense), net decreased $5 million, or 83%, compared to 2016. In 2016, other income (expense), net increased $5 million compared to 2015. For 2017, the amount includes $159 million from currency losses compared to $82 million from currency gains in 2016, arising from translation of €1.1 billion euro-denominated fixed-rate notes into U.S. dollars, each fully offset by an equal amount on the foreign currency hedges that were reclassified from accumulated OCI into earnings. See Note 9 to the financial statements under "Foreign Currency Derivatives" for additional information regarding hedging.

Income Taxes (Benefit)

In 2017, income tax benefit was $939 million compared to $195 million for 2016 of which $743 million is related to the Tax Reform Legislation under which the Company remeasured its accumulated deferred income taxes based on the new federal income tax rates. The remaining increase in tax benefit was primarily due to an increase of $89 million in PTCs from wind generation in 2017 and other state income taxes, significantly offset by a decrease in tax benefits from lower ITCs from solar plants placed in service.

In 2016, income tax benefit was $195 million compared to an expense of $21 million for 2015. The $216 million change was primarily due to an increase of $180 million in federal income tax benefits related to ITCs for solar plants placed in service and PTCs from wind generation in 2016 and a $35 million decrease in tax expense related to lower pre-tax earnings in 2016.

See FUTURE EARNINGS POTENTIAL – "Income Tax Matters – Federal Tax Reform Legislation" herein and Note 1 to the financial statements under "Income and Other Taxes" for information on how the Company recognizes the tax benefits related to federal ITCs and PTCs and Note 5 to the financial statements under "Effective Tax Rate" for additional information.

Effects of Inflation

The Company is party to long-term contracts reflecting market-based rates, including inflation expectations. Any adverse effect of inflation on the Company's results of operations has not been substantial in recent years.

FUTURE EARNINGS POTENTIAL

General

The results of operations for the past three years are not necessarily indicative of the Company's future earnings potential. The level of the Company's future earnings depends on numerous factors that affect the opportunities, challenges, and risks of the Company's competitive wholesale business. These factors include: the Company's ability to achieve sales growth while containing costs; regulatory matters; creditworthiness of customers; total generating capacity available in the Company's market areas; the successful remarketing of capacity as current contracts expire; the Company's ability to execute its growth strategy, including successful additional investments in renewable and other energy projects, and to develop and construct generating facilities.

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" and FINANCIAL CONDITION AND LIQUIDITY –

"Credit Rating Risk" herein and Note 5 to the financial statements for additional information.

In September 2017, the Company began a legal entity reorganization of various direct and indirect subsidiaries that own and operate substantially all of the 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. The Company is pursuing the sale of a 33% equity interest in the newly-formed holding company owning these solar assets, which, if successful, is expected to close in the middle of 2018. The ultimate outcome of this matter cannot be determined at this time.

MANAGEMENT'S DISCUSSION AND ANALYSIS (continued)
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Demand for electricity is primarily driven by the pace of economic growth that may be affected by changes in regional and global economic conditions, as well as renewable portfolio standards, which may impact future earnings. Other factors that could influence future earnings include weather, transmission constraints, cost of generation from units within the power pool, and operational limitations.

Power Sales Agreements

General

The Company has PPAs with some of Southern Company's traditional electric operating companies, other investor-owned utilities, independent power producers, municipalities, and other load-serving entities, as well as commercial and industrial customers. The PPAs are expected to provide the Company with a stable source of revenue during their respective terms.

Many of the Company's PPAs have provisions that require the Company or the counterparty to post collateral or an acceptable substitute guarantee in the event that S&P or Moody's downgrades the credit ratings of the respective company to an unacceptable credit rating or if the counterparty is not rated or fails to maintain a minimum coverage ratio. See FINANCIAL CONDITION AND LIQUIDITY – "Credit Rating Risk" herein for additional information.

The Company is working to maintain and expand its share of the wholesale markets. The Company expects there to be new demand for capacity that will develop in the 2018-2020 timeframe. The size of available demand and timing will vary across the wholesale markets. The Company calculates an investment coverage ratio for its generating assets based on the ratio of investment under contract to total investment using the respective generation facilities' net book value (or expected in-service value for facilities under construction or being acquired) as the investment amount. With the inclusion of the PPAs and investments associated with the wind and natural gas facilities currently under construction and the Gaskell West 1 solar facility which was acquired subsequent to December 31, 2017, as well as other capacity and energy contracts, the Company has an average investment coverage ratio of 91% through 2022 and 89% through 2027, with an average remaining contract duration of approximately 15 years. See "Acquisitions" and "Construction Projects" herein for additional information.

Natural Gas and Biomass

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

As a general matter, substantially all of the PPAs provide that the purchasers are responsible for either procuring the fuel (tolling agreements) or reimbursing the Company for substantially all of the cost of fuel or purchased power relating to the energy delivered under such PPAs. To the extent a particular generating facility does not meet the operational requirements contemplated in the PPAs, the Company may be responsible for excess fuel costs. With respect to fuel transportation risk, most of the Company's PPAs provide that the counterparties are responsible for the availability of fuel transportation to the particular generating facility.

Capacity charges that form part of the PPA payments are designed to recover fixed and variable operation and maintenance costs based on dollars-per-kilowatt year. In general, to reduce the Company's exposure to certain operation and maintenance costs, the Company has LTSAs. See Note 1 to the financial statements under "Long-Term Service Agreements" for additional information.

Solar and Wind

The Company's electricity sales from solar and wind (renewables) generating facilities are also made pursuant to long-term PPAs; however, these solar and wind PPAs do not have a capacity charge and customers either purchase the energy output of a dedicated renewable facility through an energy charge or provide the Company a certain fixed price for the electricity sold to the grid. As a result, the Company's ability to recover fixed and variable operation 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. Generally, under the solar and wind generation PPAs, the purchasing party retains the right to keep or resell the renewable energy credits.

MANAGEMENT'S DISCUSSION AND ANALYSIS (continued)
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Environmental Matters
The Company'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 Company 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 results of operations, cash flows, and financial condition. Compliance costs may result from the installation of additional environmental controls. 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 Company's operations. The Company's PPAs generally contain provisions that permit charging the counterparty with some of the new costs incurred as a result of changes in environmental laws and regulations.
Since the Company's units are newer natural gas and renewable generating facilities, costs associated with environmental compliance for these facilities have been less significant than for similarly situated coal or older natural gas generating facilities. Environmental, natural resource, and land use concerns, including the applicability of air quality limitations, the potential presence of wetlands or threatened and endangered species, the availability of water withdrawal rights, uncertainties regarding aesthetic impacts such as increased light or noise, and concerns about potential adverse health impacts can, however, increase the cost of siting and operating any type of future electric generating facility. The impact of such laws and regulations on the Company and subsequent recovery through PPA provisions cannot be determined at this time.
Environmental Laws and Regulations
Air Quality
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 Company has fossil fuel-fired generation 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 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. 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 the Company.
In 2015, the EPA published a final rule requiring certain states (including Alabama, Florida, Georgia, North Carolina, and Texas) to revise or remove the provisions of their state implementation plans (SIP) 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 Company.
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 wastewater management systems or the installation and operation of new wastewater management systems. Compliance with the ELG rule is expected to require capital expenditures and increased operational costs. 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.

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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. 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.

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.

The EPA's GHG reporting rule requires annual reporting of GHG emissions expressed in terms of metric tons of $CO_2$ equivalent emissions for a company's operational control of facilities. Based on ownership or financial control of facilities, the Company's 2016 GHG emissions were approximately 13 million metric tons of $CO_2$ equivalent. The preliminary estimate of the Company's 2017 GHG emissions on the same basis is approximately 13 million metric tons of $CO_2$ equivalent.

Income Tax Matters

Consolidated Income Taxes

On behalf of the Company, Southern Company files a consolidated federal income tax return and various state income tax returns, some of which are combined, unitary, or consolidated. Under a joint consolidated income tax allocation agreement, each Southern Company subsidiary's current and deferred tax expense is computed on a stand-alone basis and no subsidiary is allocated more current expense than would be paid if it filed a separate income tax return. In accordance with IRS regulations, each company is jointly and severally liable for the federal tax liability.

The impact of certain tax events at Southern Company and/or its other subsidiaries can, and does, affect the Company's ability to utilize certain tax credits. See "Tax Credits" and ACCOUNTING POLICIES – "Application of Critical Accounting Policies and Estimates" herein and Note 5 to the financial statements for additional information.

The Company currently has unutilized federal ITC and PTC carryforwards totaling approximately $2.0 billion, and thus anticipates utilizing third-party tax equity partnerships as one of the financing sources to fund its renewable growth strategy where the tax partner will take significantly all of the respective federal tax benefits. These tax equity partnerships are expected to be consolidated in the Company's financial statements using a hypothetical liquidation at book value (HLBV) methodology to allocate partnership gains and losses to the Company.

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 20% each year until it completely phases out for qualified property placed in service after December 31, 2027. Further, the business interest deduction is

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limited to 30% of taxable income excluding interest, net operating loss (NOL) carryforward, and depreciation and amortization through December 31, 2021 and thereafter to 30% of taxable income excluding interest and NOL carryforwards.

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 Southern Company's 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 $743 million, primarily due to the impact of the reduction of the corporate income tax rate on deferred tax assets and liabilities.

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.

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.

Tax Credits

The Tax Reform Legislation retained the renewable energy incentives that were included in the Protecting Americans from Tax Hikes (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 related to its investment in new solar facilities acquired or constructed and receives PTCs related to the first 10 years of energy production from its wind facilities, which have had, and will continue to have, a material impact on the Company's cash flows and net income. At December 31, 2017, the Company had approximately $2.0 billion of unutilized ITCs and PTCs, which are currently expected to be fully utilized by 2027, but could be further delayed as a result of the Company's continued growth strategy, as well as the impacts from the Tax Reform Legislation. 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" and "Effective Tax Rate" for additional information regarding utilization and amortization of credits and the tax benefit related to basis differences.

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, approximately $130 million of positive cash flows is expected to result from bonus depreciation for the 2017 tax year. Should Southern Company have a NOL in 2018, all of these cash flows may not be fully realized in 2018. In addition, any cash flows resulting from bonus depreciation will also be impacted by the Company's use of third-party tax equity arrangements. See 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.

Legal Entity Reorganization

In September 2017, the Company began a legal entity reorganization of various direct and indirect subsidiaries that own and operate substantially all of the 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 Company 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.

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Acquisitions

During 2017 and subsequent to December 31, 2017, in accordance with its overall growth strategy, the Company acquired the projects discussed below, as well as the Cactus Flats wind facility discussed under "Construction Projects" herein. See Note 11 to the financial statements for additional information.

| Project Facility | Resource | Seller, Acquisition Date | Approximate Nameplate Capacity (MW) | Location | Percentage Ownership | Actual/Expected COD | PPA Counterparties | 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 | Google Energy, LLC | 12 years |
| Asset Acquisitions Subsequent to December 31, 2017 | | | | | | | | |
| Gaskell West 1 | Solar | Recurrent Energy Development Holdings, LLC, January 26, 2018 | 20 | Kern County, CA | 100% of Class B(*) | March 2018 | Southern California Edison | 20 years |

(*) The Company owns 100% of the class B membership interest under a tax equity partnership agreement.

Construction Projects

Construction Projects Completed and in Progress

During 2017, in accordance with its overall growth strategy, the Company completed construction of and placed in service, or continued construction of, the projects set forth in the table below.

| Project Facility | Resource | Approximate Nameplate Capacity (MW) | Location | Ownership Percentage | Actual / Expected COD | PPA Counterparties | PPA Contract Period |
|---|---|---|---|---|---|---|---|
| Construction Projects Completed During the Year Ended December 31, 2017 | | | | | | | |
| East Pecos | Solar | 120 | Pecos County, TX | 100 % | March 2017 | Austin Energy | 15 years |
| Lamesa | Solar | 102 | Dawson County, TX | 100 % | April 2017 | City of Garland, Texas | 15 years |
| Projects Under Construction at December 31, 2017 | | | | | | | |
| Cactus Flats | Wind | 148 | Concho County, TX | 100 % (*) | Third quarter 2018 | General Motors and General Mills | 12 years and 15 years |
| Mankato Expansion | Natural Gas | 345 | Mankato, MN | 100% | Second quarter 2019 | Northern States Power Company | 20 years |

(*) On July 31, 2017, the Company purchased 100% of the Cactus Flats facility and commenced construction. Upon placing the facility in service, the Company 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.

Total aggregate construction costs for projects under construction at December 31, 2017, 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, total costs of construction incurred for these projects was $188 million, all of which remained in CWIP.

Development Projects

During 2017, as part of the Company's renewable development strategy, the Company 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.

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During 2016, the Company 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, the Company 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.

FERC Matters

The Company has authority from the FERC to sell electricity at market-based rates. Since 2008, that authority, for certain balancing authority areas, has been conditioned on compliance with the requirements of an energy auction, which the FERC found to be tailored mitigation that addresses potential market power concerns. In accordance with FERC regulations governing such authority, the traditional electric operating companies and the Company 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 the Company'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 the Company 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 the Company filed a request for rehearing and filed their response with the FERC in 2015.

In December 2016, the traditional electric operating companies and the Company 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 the Company'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 the Company'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 the Company's June 29, 2017 triennial updated market power analysis. The FERC directed the traditional electric operating companies and the Company 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 the Company 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.

Other Matters

The Company is involved in various other matters being litigated and regulatory matters that could affect future earnings. In addition, the Company is subject to certain claims and legal actions arising in the ordinary course of business. The Company's business activities are subject to extensive governmental regulation related to public health and the environment, such as regulation of air emissions and water discharges. Litigation over environmental issues and claims of various types, including property damage, personal injury, common law nuisance, and citizen enforcement of environmental requirements, such as 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 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, management does not anticipate that the ultimate liabilities, if any, arising from such current proceedings would have a material effect on the Company's financial statements.
During 2015, the Company indirectly acquired a 51% membership interest in RE Roserock LLC (Roserock), the owner of the Roserock facility in Pecos County, Texas, which was under construction by Recurrent Energy, LLC and was subsequently placed in service in November 2016. Prior to placing the facility in service, certain solar panels were damaged during installation. While the facility currently is generating energy consistent with operational expectations and PPA obligations, the Company is pursuing remedies under its insurance policies and other contracts to repair or replace these solar panels. In connection therewith, the Company is withholding payments of approximately $26 million from the construction contractor, who has placed a lien on the

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Roserock facility for the same amount. The amounts withheld are included in other accounts payable and other current liabilities on the Company's consolidated balance sheets. On May 18, 2017, Roserock filed a lawsuit in the state district court in Pecos County, Texas, against XL Insurance America, Inc. (XL) and North American Elite Insurance Company (North American Elite) seeking recovery from an insurance policy for damages resulting from a hail storm and certain installation practices by the construction contractor, McCarthy Building Companies, Inc. (McCarthy). On May 19, 2017, Roserock filed a separate lawsuit against McCarthy in the state district court in Travis County, Texas alleging breach of contract and breach of warranty for the damages sustained at the Roserock facility, which has since been moved to the U.S. District Court for the Western District of Texas. On May 22, 2017, McCarthy filed a counter lawsuit against Roserock, Array Technologies, Inc., Canadian Solar (USA), Inc., XL, and North American Elite in the U.S. District Court for the Western District of Texas alleging, among other things, breach of contract, and requesting foreclosure of mechanic's liens against Roserock. On July 18, 2017, the U.S. District Court for the Western District of Texas consolidated the two pending lawsuits. On December 11, 2017, the U.S. District Court for the Western District of Texas dismissed McCarthy's claims against Canadian Solar (USA), Inc. and dismissed cross-claims that XL and North American Elite had sought to bring against Roserock. The Company intends to vigorously pursue and defend these matters, the ultimate outcome of which cannot be determined at this time.

## ACCOUNTING POLICIES

### Application of Critical Accounting Policies and Estimates

The 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 the Company's results of operations and related disclosures. Different assumptions and measurements could produce estimates that are significantly different from those recorded in the financial statements. Senior management has reviewed and discussed the following critical accounting policies and estimates with the Audit Committee of Southern Company's Board of Directors.

### Revenue Recognition

The Company's revenue recognition depends on appropriate classification and documentation of transactions in accordance with GAAP. In general, the Company's power sale transactions, which include PPAs, can be classified in one of four categories: leases, non-derivatives or normal sale derivatives, derivatives designated as cash flow hedges, and derivatives not designated as hedges. For more information on derivative transactions, see FINANCIAL CONDITION AND LIQUIDITY – "Market Price Risk" herein and Notes 1 and 9 to the financial statements. The Company's revenues are dependent upon significant judgments used to determine the appropriate transaction classification, which must be documented upon the inception of each contract.

#### Lease Transactions

The Company considers the following factors to determine whether the sales contract is a lease:
- Assessing whether specific property is explicitly or implicitly identified in the agreement;
- Determining whether the fulfillment of the arrangement is dependent on the use of the identified property; and
- Assessing whether the arrangement conveys to the purchaser the right to use the identified property.

If the contract meets the above criteria for a lease, the Company performs further analysis as to whether the lease is classified as operating, financing, or sales-type. All of the Company's power sales contracts that are determined to be leases are accounted for as operating leases and the capacity revenue is recognized on a straight-line basis over the term of the contract and is included in the Company's operating revenues. Energy revenues and other contingent revenues are recognized in the period the energy is delivered or the service is rendered.

#### Non-Derivative and Normal Sale Derivative Transactions

If the power sales contract is not classified as a lease, the Company further considers the following factors to determine proper classification:
- Assessing whether the contract meets the definition of a derivative;
- Assessing whether the contract meets the definition of a capacity contract;

- Assessing the probability at inception and throughout the term of the individual contract that the contract will result in physical delivery; and
- Ensuring that the contract quantities do not exceed available generating capacity (including purchased capacity).

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Contracts that do not meet the definition of a derivative or are designated as normal sales (i.e. capacity contracts which provide for the sale of electricity that involve physical delivery in quantities within the Company's available generating capacity) are accounted for as executory contracts. The related capacity revenue, if any, is recognized on an accrual basis in amounts equal to the lesser of the cumulative levelized amount or the cumulative amount billable under the contract over the respective contract periods. Revenues related to energy and ancillary services are recognized in the period the energy is delivered or the service is rendered.

Cash Flow Hedge Transactions

The Company further considers the following in designating other derivative contracts for the sale of electricity as cash flow hedges of anticipated sale transactions:

- Identifying the hedging instrument, the forecasted hedged transaction, and the nature of the risk being hedged; and
- Assessing hedge effectiveness at inception and throughout the contract term.

These contracts are accounted for on a fair value basis and are recorded in AOCI over the life of the contract. Realized gains and losses are then recognized in operating revenues as incurred.

Mark-to-Market Transactions

Contracts for sales of electricity, which meet the definition of a derivative and that either do not qualify or are not designated as normal sales or as cash flow hedges, are accounted for on a fair value basis and are recorded in operating revenues.

Impairment of Long-Lived Assets and Intangibles

The Company's investments in long-lived assets are primarily generation assets, whether in service or under construction. The Company's intangible assets arise from certain acquisitions and consist of acquired PPAs, which are amortized to revenue over the term of the respective PPAs. The Company evaluates the carrying value of these assets whenever indicators of potential impairment exist. Examples of impairment indicators could include significant changes in construction schedules, current period losses combined with a history of losses or a projection of continuing losses, a significant decrease in market prices, and the inability to remarket generating capacity for an extended period. If an indicator exists, the asset is tested for recoverability by comparing the asset carrying value to the sum of the undiscounted expected future cash flows directly attributable to the asset. If the estimate of undiscounted future cash flows is less than the carrying value of the asset, the fair value of the asset is determined and a loss is recorded. A high degree of judgment is required in developing estimates related to these evaluations, which are based on projections of various factors, including the following:

- Future demand for electricity based on projections of economic growth and estimates of available generating capacity;
- Future power and natural gas prices, which have been quite volatile in recent years; and
- Future operating costs.

Acquisition Accounting

The Company may acquire generation assets as part of its overall growth strategy. At the time of an acquisition, the Company will assess if these assets and activities meet the definition of a business. For acquisitions that meet the definition of a business, the Company includes operating results from the date of acquisition in its consolidated financial statements. The purchase price, including any contingent consideration, is allocated based on the fair value of the identifiable assets acquired and liabilities assumed (including any intangible assets). Assets acquired that do not meet the definition of a business are accounted for as an asset acquisition.

The purchase price of each asset acquisition is allocated based on the relative fair value of assets acquired. Determining the fair value of assets acquired and liabilities assumed requires management judgment and the Company may engage independent valuation experts to assist in this process. Fair values are determined by using market participant assumptions, and typically include the timing and amounts of future cash flows, incurred construction costs, the nature of acquired contracts, discount rates, power market prices, and expected asset lives. Any due diligence or transition costs incurred by the Company for potential or successful acquisitions are expensed as incurred.

Contingent consideration primarily relates to fixed amounts due to the seller once the facility is placed in service. For contingent consideration with variable payments, the Company fair values the arrangement with any changes recorded in the consolidated statements of income. See Note 8 to the financial statements for additional fair value information.

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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 Company operates.

On behalf of the Company, 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, as well as Southern 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 the Company's financial statements.

Given the significant judgment involved in estimating NOL and tax credit carryforwards and multi-state apportionments for all subsidiaries, the 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, the 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. The 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 cannot be determined at this time. See FUTURE EARNINGS POTENTIAL – "Income Tax Matters – Federal Tax Reform Legislation" herein and Note and 5 to the financial statements under "Current and Deferred Income Taxes" for additional information.

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.

The Company has completed the evaluation of all revenue streams and determined that the adoption of ASC 606 will not change the current timing or amounts of revenue recognized in the Company's financial statements. Some contractual arrangements, such as certain capacity and energy payments, are excluded from the scope of ASC 606 and included in the scope of the current leasing guidance or the current derivative guidance.

The new standard is effective for reporting periods beginning after December 15, 2017. The Company applied the modified retrospective method of adoption effective January 1, 2018. The 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. The adoption of ASC 606 did not result in a cumulative adjustment.

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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. ASU 2016-02 is effective for fiscal years beginning after December 15, 2018 and the Company will adopt the new standard effective January 1, 2019.
The 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, the Company has substantially completed a detailed inventory and analysis of its leases where the majority relate to land leases for its renewable generation facilities. While the Company has not yet determined the ultimate impact, adoption of ASU 2016-02 is expected to have a significant impact on the Company's balance sheet for lessee arrangements.
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. The Company adopted ASU 2016-18 effective January 1, 2018 with no material 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 other income (expense) in the income statement. Additionally, only the service cost component related to construction labor is eligible for capitalization, when applicable. The Company adopted ASU 2017-07 which is effective for periods beginning after December 15, 2017; however, since the Company only became a sponsor of a qualified pension plan and postretirement benefit plan in December 2017, no retrospective presentation of net periodic benefits costs for 2016 or 2017 is required. See Note 2 to the financial statements for additional information.
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. The Company adopted ASU 2017-12 effective January 1, 2018 with no material impact on its financial statements.
FINANCIAL CONDITION AND LIQUIDITY
Overview
The Company's financial condition remained stable at December 31, 2017. The Company's cash requirements primarily consist of funding ongoing business operations, common stock dividends, distributions to noncontrolling interests, capital expenditures, and debt maturities. Capital expenditures and other investing activities may include investments in acquisitions or new construction associated with the Company's overall growth strategy and to maintain the existing generation fleet's performance. Operating cash flows, which may include the utilization of tax credits, will only provide a portion of the Company's cash needs. For the three-year period from 2018 through 2020, the Company's projected dividends, capital expenditures, and debt maturities are expected to exceed operating cash

flows. The Company plans to finance future cash needs in excess of its operating cash flows primarily through debt issuances, borrowings from financial institutions, and equity contributions from Southern Company. The Company intends to continue to monitor its access to short-term and long-term capital markets as well as bank credit agreements as needed to meet its future capital and liquidity needs. See "Sources of Capital" herein for additional information on lines of credit.

The Company also anticipates utilizing third-party tax equity partnerships as one of the financing sources to fund its renewable growth strategy where the tax partner will take significantly all of the federal tax benefits. These tax equity partnerships are expected to be consolidated in the Company's financial statements using a HLBV methodology to allocate partnership gains and losses to the Company. The Company recently secured third-party tax equity funding for the Cactus Flats project subject to

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achieving commercial operation and various other customary conditions to closing as well as for the Gaskell West 1 project. The ultimate outcome of these matters cannot be determined at this time.

In addition, the Company is pursuing the sale of a 33% equity interest in a newly-formed holding company that owns substantially all of the Company's solar assets, which, if successful, is expected to close in the middle of 2018. Proceeds from the sale may be used for debt redemptions, common stock dividends, working capital, and general corporate purposes as well to support the Company's continuing growth strategy.

Net cash provided from operating activities totaled $1.2 billion in 2017, an increase of $816 million compared to 2016. The increase in net cash provided from operating activities was primarily due to income tax refunds received and an increase in energy sales from new solar and wind facilities, partially offset by an increase in interest paid. As of December 31, 2017, the Company had $2.0 billion of unutilized ITCs and PTCs which are not expected to be fully utilized until 2027. See FUTURE EARNINGS POTENTIAL – "Income Tax Matters – Tax Credits" herein for additional information. Net cash provided from operating activities totaled $339 million in 2016, a decrease of $664 million compared to 2015 primarily due to an increase in unutilized ITCs and PTCs.

Net cash used for investing activities totaled $1.6 billion, $4.8 billion, and $2.5 billion in 2017, 2016, and 2015, respectively, and was primarily due to acquisitions and the construction of renewable and natural gas facilities. See FUTURE EARNINGS POTENTIAL – "Acquisitions" and "Construction Projects" herein for additional information.

Net cash used for financing activities totaled $502 million in 2017 primarily due to payments of common stock dividends and distributions to noncontrolling interests. Net cash provided from financing activities totaled $4.7 billion in 2016 primarily due to the issuance of additional senior notes and capital contributions from Southern Company and noncontrolling interests. Net cash provided from financing activities totaled $2.3 billion in 2015 primarily due to the issuance of additional senior notes and a 13-month term loan.

Significant balance sheet changes include a $1.0 billion increase in plant in service primarily due to new solar and wind facilities being acquired or placed in service, a $284 million increase in deferred income taxes primarily due to additional unutilized PTCs, and a $113 million increase in CWIP primarily due to the construction of a new wind facility and the Mankato natural gas expansion project. In addition, ITC benefits that are deferred and amortized over the asset lives increased $45 million as a result of additional ITCs from new solar facilities being placed in service, offset by ongoing ITC amortization. Other significant changes include a $970 million decrease in cash and cash equivalents and a $456 million decrease in acquisitions payable.

Sources of Capital

The Company plans to obtain the funds required for acquisitions, construction, development, debt maturities, and other purposes from operating cash flows, external securities issuances, borrowings from financial institutions, tax equity partnership contributions, and equity contributions from Southern Company. The Company also plans to utilize funds resulting from any potential sale of a 33% equity interest in substantially all of its solar asset portfolio, if completed. However, the amount, type, and timing of any future financings, if needed, will depend upon prevailing market conditions, regulatory approval, and other factors. With respect to the public offering of securities, the Company (excluding its subsidiaries) issues and offers debt registered on registration statements filed with the SEC under the Securities Act of 1933, as amended.

At December 31, 2017, the Company's current liabilities exceeded current assets by $474 million due to long-term debt maturing in the next 12 months, the use of short-term debt as a funding source, and fluctuations in cash needs, due to both seasonality and the stage of acquisitions and construction projects. The Company believes the need for working capital can be adequately met by utilizing the commercial paper program, the Facility (as defined below), borrowings from financial institutions, the debt capital markets, the commercial paper program, and operating cash flows.

The Company obtains financing separately without credit support from any affiliate. To meet liquidity and capital resource requirements, the Company had cash and cash equivalents of approximately $129 million at December 31, 2017.

The Company's commercial paper program is used to finance acquisition and construction costs related to electric generating facilities and for general corporate purposes, including maturing debt. The Company's subsidiaries are not issuers under the commercial paper program.

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Details of commercial paper were as follows:

| | Commercial Paper at the End of the Period | | Commercial Paper 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 | $105 | 2.0% | $232 | 1.4% | $ 628 |
| December 31, 2016 | $— | N/A | $56 | 0.8% | $ 310 |
| December 31, 2015 | $— | N/A | $166 | 0.5% | $ 385 |

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

Company Credit Facilities

At December 31, 2017, the Company had a committed credit facility (Facility) of $750 million expiring in 2022, of which $22 million has been used for letters of credit and $728 million remains unused. In May 2017, the Company amended the Facility, which, among other things, extended the maturity date from 2020 to 2022 and increased the Company's borrowing ability under this Facility to $750 million from $600 million. The Company's subsidiaries are not borrowers under the Facility. Proceeds from the Facility may be used for working capital and general corporate purposes as well as liquidity support for the Company's commercial paper program. Subject to applicable market conditions, the Company expects to renew or replace the Facility, as needed, prior to expiration. In connection therewith, the Company may extend the maturity date and/or increase or decrease the lending commitment thereunder. See Note 6 to the financial statements under "Bank Credit Arrangements" for additional information.

The Facility, as well as the Company's term loan agreements, contains a covenant that limits the ratio of debt to capitalization (as defined in the Facility) to a maximum of 65% and contains a cross-default provision that is restricted only to indebtedness of the Company. For purposes of this definition, debt excludes any project debt incurred by certain subsidiaries of the Company to the extent such debt is non-recourse to the Company, and capitalization excludes the capital stock or other equity attributable to such subsidiary. The Company is currently in compliance with all covenants in the Facility.

The Company also has a $120 million continuing letter of credit facility expiring in 2019 for standby letters of credit. At December 31, 2017, $101 million has been used for letters of credit, primarily as credit support for PPA requirements, and $19 million remains unused. The Company's subsidiaries are not parties to this letter of credit facility.

In addition, at both December 31, 2017 and 2016, the Company had $113 million of cash collateral posted related to PPA requirements.

Subsidiary Project Credit Facilities

In connection with the construction of solar facilities by RE Tranquillity LLC, RE Garland Holdings LLC, and RE Roserock LLC, indirect subsidiaries of the Company, each subsidiary had entered into separate credit agreements (Project Credit Facilities), which were non-recourse to the Company (other than the subsidiary party to the agreement). Each Project Credit Facility provided (a) a senior secured construction loan credit facility, (b) a senior secured bridge loan facility, and (c) a senior secured letter of credit facility that was secured by the membership interests of the respective project company, with proceeds directed to finance project costs related to the respective solar facilities. Each Project Credit Facility was secured by the assets of the applicable project subsidiary and membership interests of the applicable project subsidiary. The Tranquillity, Garland, and Roserock Project Credit Facilities were fully repaid on October 14, 2016, December 29, 2016, and January 31, 2017, respectively.

Furthermore, in connection with the acquisition of the Henrietta solar facility on July 1, 2016, a subsidiary of the Company assumed a $217 million construction loan, which was fully repaid in September 2016.

Financing Activities

Senior Notes

In November 2017, the Company issued $525 million aggregate principal amount of Series 2017A Floating Rate Senior Notes due December 20, 2020, which bear interest based on three-month LIBOR. The net proceeds were used to redeem all of the $500

MANAGEMENT'S DISCUSSION AND ANALYSIS (continued)
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million aggregate principal amount of Series 2015D 1.85% Senior Notes due December 1, 2017 and to repay a portion of the Company's outstanding short-term debt.

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

Other Debt

In September 2017, the Company 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 additional $40 million of proceeds were used to repay existing indebtedness and for other general corporate purposes. At December 31, 2017, this outstanding term loan was included in securities due within one year.

In addition, during 2017, the Company issued a total of $21 million in letters of credit under the Company's credit facilities.

Credit Rating Risk

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

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

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 | $ 39 |
| At BBB- and/or Baa3 | $ 415 |
| At BB+ and/or Ba1 (*) | $ 1,118 |

(*) Any additional credit rating downgrades at or below BB- and/or Ba3 could increase collateral requirements up to an additional $38 million.

Included in these amounts are certain agreements that could require collateral in the event that Alabama Power or Georgia Power has a credit rating change to below investment grade. Generally, collateral may be provided by a Southern Company guaranty, letter of credit, or cash. Additionally, a credit rating downgrade could impact the ability of the Company to access capital markets and would be likely to impact the cost at which it does so.

In addition, the Company has a PPA that could require collateral, but not accelerated payment, in the event of a downgrade of the Company's credit. The PPA requires credit assurances without stating a specific credit rating. The amount of collateral required would depend upon actual losses resulting from a credit downgrade.

On March 24, 2017, S&P revised its consolidated credit rating outlook for Southern Company and its subsidiaries (including the Company) from stable to negative.

While it is unclear how the credit rating agencies 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, including the Company, may be negatively impacted. Absent actions by the Company to mitigate the resulting impacts, which, among other alternatives, could include adjusting the Company's capital structure, the Company's credit ratings could be negatively affected.

Market Price Risk

The Company is exposed to market risks, primarily commodity price risk, interest rate risk, and occasionally foreign currency exchange rate risk. To manage the volatility attributable to these exposures, the Company nets its exposures, where possible, to take advantage of natural offsets and enters into various derivative transactions for the remaining exposures pursuant to the Company's policies in areas such as counterparty exposure and risk management practices. The Company's policy is that derivatives are to be used primarily for hedging purposes and mandates strict adherence to all applicable risk management policies. Derivative positions are monitored using techniques including, but not limited to, market valuation, value at risk, stress testing, and sensitivity analysis. Derivative instruments are recognized at fair value in the consolidated balance sheets as either assets or liabilities and are presented on a gross basis. In the statements of cash flows, the cash impacts of settled energy-related and interest rate derivatives are recorded as operating activities.

At December 31, 2017, the Company had $945 million of long-term variable rate notes outstanding. If the Company sustained a 100 basis point change in interest rates for its variable interest rate exposure, the change would effect annualized interest expense by approximately $9 million at December 31, 2017. Since a significant portion of outstanding indebtedness bears interest at fixed rates, the Company is not aware of any facts or circumstances that would significantly affect exposure on existing indebtedness in the near term. However, the impact on future financing costs cannot be determined at this time.

The Company had foreign currency denominated debt of €1.1 billion at December 31, 2017. The 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.

Because energy from the Company's facilities is primarily sold under long-term PPAs with tolling agreements and provisions shifting substantially all of the responsibility for fuel cost to the counterparties, the Company's exposure to market volatility in commodity fuel prices and prices of electricity is generally limited. However, the Company has been and may continue to be exposed to market volatility in energy-related commodity prices as a result of uncontracted generating capacity.

For the years ended December 31, 2017 and 2016, the changes in fair value of energy-related derivative contracts associated with both power and natural gas positions were as follows:

| | 2017 | 2016 |
|---|---|---|
| | (in millions) | |
| Contracts outstanding at the beginning of period, assets (liabilities), net | $16 | $1 |
| Contracts realized or settled | (17) | (3) |
| Current period changes (*) | (9) | 18 |
| Contracts outstanding at the end of period, assets (liabilities), net | $(10) | $16 |

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

For the years ending December 31, 2017 and 2016, the changes in contracts outstanding were attributable to both the volume and the prices of power and natural gas as follows:

| | 2017 | 2016 |
|---|---|---|
| Power – net sold | | |
| MWH (in millions) | 3.0 | 6.1 |
| Weighted average contract cost per MWH above (below) market prices (in dollars) | $(2.67) | $1.45 |
| Natural Gas – net purchased | | |
| Commodity - mmBtu (in millions) | 14.4 | 27.1 |
| Commodity - weighted average contract cost per mmBtu above (below) market prices (in dollars) | $0.12 | $(0.27) |

Gains and losses on energy-related derivatives designated as cash flow hedges which are used by the Company to hedge anticipated purchases and sales are initially deferred in OCI before being recognized in income in the same period as the hedged transactions are reflected in earnings. Gains and losses on energy-related derivative contracts that are not designated or fail to qualify as hedges are recognized in the consolidated statements of income as incurred.

The Company uses over-the-counter contracts that are not exchange traded but are fair valued using prices which are market observable, and thus fall into Level 2 of the fair value hierarchy. See Note 8 to the financial statements for further discussion of fair value measurements. The energy-related derivative contracts outstanding at December 31, 2017 all mature in 2018.

The Company is exposed to losses related to financial instruments in the event of counterparties' nonperformance. The Company only enters into agreements and material transactions with counterparties that have investment grade credit ratings by S&P and Moody's or with counterparties who have posted collateral to cover potential credit exposure. The Company has also established risk management policies and controls to determine and monitor the creditworthiness of counterparties in order to mitigate the Company's exposure to counterparty credit risk. Therefore, the Company does not anticipate a material adverse effect on the financial statements as a result of counterparty nonperformance. See Note 1 to the financial statements under "Financial Instruments" and Note 9 to the financial statements for additional information.

Capital Requirements and Contractual Obligations

The capital program of the Company is subject to periodic review and revision and is currently estimated to total $7.2 billion over the next five years through 2022. This includes approximately $0.9 billion in committed construction, capital improvements, and work to be performed under LTSAs, totaling approximately $400 million for 2018 and an average of approximately $137 million each year from 2019 through 2022. In addition, the capital program includes a further $6.3 billion in planned expenditures for plant acquisitions and placeholder growth, which averages approximately $1.3 billion per year. Planned expenditures for plant acquisitions and placeholder growth may vary materially due to market opportunities and the Company's ability to execute its growth strategy. Actual construction costs may vary from these estimates because of numerous factors such as: changes in business conditions; changes in the expected environmental compliance program; changes in environmental laws and regulations; the outcome of any legal challenges to the environmental rules; changes in FERC rules and regulations; changes in load projections; changes in legislation; the cost and efficiency of construction labor, equipment, and materials; project scope and design changes; and the cost of capital. See Note 11 to the financial statements for additional information.

Other funding requirements related to obligations associated with scheduled maturities of long-term debt, as well as the related interest, leases, derivative obligations, other purchase commitments, and pension and other postretirement benefit plans are detailed in the contractual obligations table that follows. See Notes 1, 2, 5, 6, 7, and 9 to the financial statements for additional information.

MANAGEMENT'S DISCUSSION AND ANALYSIS (continued)
Southern Power Company and Subsidiary Companies 2017 Annual Report

Contractual Obligations

Contractual obligations at December 31, 2017 were as follows:

| | 2018 | 2019-2020 | 2021-2022 | After 2022 | Total |
|---|---|---|---|---|---|
| | (in millions) | | | | |
| Long-term debt[(a)] — | | | | | |
| Principal | $770 | $1,425 | $977 | $2,630 | $5,802 |
| Interest | 189 | 334 | 278 | 1,524 | 2,325 |
| Financial derivative obligations[(b)] | 13 | — | — | — | 13 |
| Operating leases[(c)] | 22 | 45 | 45 | 815 | 927 |
| Purchase commitments — | | | | | |
| Capital[(d)] | 1,099 | 3,661 | 1,750 | — | 6,510 |
| Fuel[(e)] | 453 | 555 | 327 | 56 | 1,391 |
| Purchased power[(f)] | 40 | 82 | 42 | — | 164 |
| Other[(g)] | 149 | 315 | 216 | 1,770 | 2,450 |
| Pension and other postretirement benefit plans[(h)] | — | 1 | — | — | 1 |
| Total | $2,735 | $6,418 | $3,635 | $6,795 | $19,583 |

(a) All amounts are reflected based on final maturity dates and include the effects of interest rate derivatives employed to manage interest rate risk and effects of foreign currency swaps employed to manage foreign currency exchange rate risk. Included in debt principal is a $77 million gain related to the foreign currency hedge of €1.1 billion. The Company plans to continue, when economically feasible, to retire higher-cost securities and replace these obligations with lower-cost capital if market conditions permit.

(b) For additional information, see Notes 1 and 9 to the financial statements.

(c) Operating lease commitments include certain land leases for solar and wind facilities that are subject to annual price escalation based on indices. See Note 7 to the financial statements under "Commitments" for additional information.

(d) The Company provides estimated capital expenditures for a five-year period, including capital expenditures associated with environmental regulations. Included in these amounts are planned expenditures for plant acquisitions and placeholder growth, which averages approximately $1.3 billion per year, and may vary materially each year due to market opportunities and the Company's ability to execute its growth strategy. Amounts represent current estimates of total expenditures, excluding capital expenditures covered under LTSAs which are reflected in "Other." See Note (g) below. At December 31, 2017, significant purchase commitments were outstanding in connection with the construction program.

(e) Primarily includes commitments to purchase, transport, and store natural gas. Amounts reflected are based on contracted cost and may contain provisions for price escalation. Amounts reflected for natural gas purchase commitments are based on various indices at the time of delivery and have been estimated based on the New York Mercantile Exchange future prices at December 31, 2017.

(f) Purchased power commitments will be resold under a third party agreement at cost.

(g) Includes commitments related to LTSAs, operation and maintenance agreements, and transmission. LTSAs include price escalation based on inflation indices. Transmission commitments are based on the Southern Company system's current tariff rate for point-to-point transmission.

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

MANAGEMENT'S DISCUSSION AND ANALYSIS (continued)
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Cautionary Statement Regarding Forward-Looking Statements

The Company's 2017 Annual Report contains forward-looking statements. Forward-looking statements include, among other things, statements concerning the strategic goals for the Company's business, economic conditions, fuel and environmental cost recovery, current and proposed environmental regulations and related compliance plans and estimated expenditures, pending or potential litigation matters, access to sources of capital, financing activities, estimated sales and purchases under power sale and purchase agreements, timing of expected future capacity need in existing markets, completion dates of construction projects, projections for the qualified pension plan and postretirement benefit plans contributions, filings with federal regulatory authorities, impacts of the Tax Reform Legislation, federal and state income tax benefits, 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 Company is 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 Company;
- 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 Company operates;
- variations in demand for electricity, 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 fuels;
- transmission constraints;
- effects of inflation;
- the ability to control costs and avoid cost overruns during the development and construction of generating facilities, to construct facilities in accordance with the requirements of permits and licenses, and to satisfy any environmental performance standards, including the requirements of tax credits and other incentives;
- investment performance of the Company's employee and retiree benefit plans;
- advances in technology;
- ongoing renewable energy partnerships and development agreements;
- state and federal rate regulations;
- the ability to successfully operate generating facilities and the successful performance of necessary corporate functions;
- internal restructuring or other restructuring options that may be pursued;
- potential business strategies, including acquisitions or dispositions of assets or businesses, including the potential sale of a 33% equity interest in substantially all of the Company's solar assets, which cannot be assured to be completed or beneficial to the Company;
- the ability of counterparties of the Company to make payments as and when due and to perform as required;
- the ability to obtain new short- and long-term contracts with wholesale customers;
- the direct or indirect effect on the Company's business resulting from cyber intrusion or physical attack and the threat of physical attacks;

- interest rate fluctuations and financial market conditions and the results of financing efforts;
- changes in the Company's credit ratings, including impacts on interest rates, access to capital markets, and collateral requirements;
- the impacts of any sovereign financial issues, including impacts on interest rates, access to capital markets, impacts on foreign currency exchange rates, counterparty performance, and the economy in general;

- the ability of the Company to obtain additional generating capacity (or sell excess generating capacity) at competitive prices;
- catastrophic events such as fires, earthquakes, explosions, floods, tornadoes, hurricanes and other storms, droughts, pandemic health events such as influenzas, or other similar occurrences;
- the direct or indirect effects on the Company's business resulting from incidents affecting the U.S. electric grid or operation of generating resources;
- the effect of accounting pronouncements issued periodically by standard-setting bodies; and
- other factors discussed elsewhere herein and in other reports filed by the Company from time to time with the SEC.

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

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CONSOLIDATED STATEMENTS OF INCOME
For the Years Ended December 31, 2017, 2016, and 2015
Southern Power Company and Subsidiary Companies 2017 Annual Report

| | 2017 | 2016 | 2015 |
|---|---|---|---|
| | (in millions) | | |
| Operating Revenues: | | | |
| Wholesale revenues, non-affiliates | $1,671 | $1,146 | $964 |
| Wholesale revenues, affiliates | 392 | 419 | 417 |
| Other revenues | 12 | 12 | 9 |
| Total operating revenues | 2,075 | 1,577 | 1,390 |
| Operating Expenses: | | | |
| Fuel | 621 | 456 | 441 |
| Purchased power | 149 | 102 | 93 |
| Other operations and maintenance | 386 | 354 | 260 |
| Depreciation and amortization | 503 | 352 | 248 |
| Taxes other than income taxes | 48 | 23 | 22 |
| Total operating expenses | 1,707 | 1,287 | 1,064 |
| Operating Income | 368 | 290 | 326 |
| Other Income and (Expense): | | | |
| Interest expense, net of amounts capitalized | (191) | (117) | (77) |
| Other income (expense), net | 1 | 6 | 1 |
| Total other income and (expense) | (190) | (111) | (76) |
| Earnings Before Income Taxes | 178 | 179 | 250 |
| Income taxes (benefit) | (939) | (195) | 21 |
| Net Income | 1,117 | 374 | 229 |
| Less: Net income attributable to noncontrolling interests | 46 | 36 | 14 |
| Net Income Attributable to the Company | $1,071 | $338 | $215 |

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

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CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME
For the Years Ended December 31, 2017, 2016, and 2015
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| | 2017 | 2016 | 2015 |
|---|---|---|---|
| | (in millions) | | |
| Net Income | $1,117 | $374 | $229 |
| Other comprehensive income (loss): | | | |
| Qualifying hedges: | | | |
| Changes in fair value, net of tax of $39, $(17), and $-, respectively | 63 | (27) | — |
| Reclassification adjustment for amounts included in net income, net of tax of $(46), $36, and $-, respectively | (73) | 58 | 1 |
| Total other comprehensive income (loss) | (10) | 31 | 1 |
| Less: Comprehensive income attributable to noncontrolling interests | 46 | 36 | 14 |
| Comprehensive Income Attributable to the Company | $1,061 | $369 | $216 |

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
Southern Power Company and Subsidiary Companies 2017 Annual Report

| | 2017 | 2016 | 2015 |
|---|---|---|---|
| | (in millions) | | |
| Operating Activities: | | | |
| Net income | $1,117 | $374 | $229 |
| Adjustments to reconcile net income to net cash provided from operating activities — | | | |
| Depreciation and amortization, total | 536 | 370 | 254 |
| Deferred income taxes | (263) | (1,063) | 42 |
| Investment tax credits | — | — | 162 |
| Amortization of investment tax credits | (57) | (37) | (19) |
| Collateral deposits | (4) | (102) | — |
| Accrued income taxes, non-current | 14 | (109) | 109 |
| Income taxes receivable, non-current | (61) | (13) | — |
| Other, net | (9) | 12 | (2) |
| Changes in certain current assets and liabilities — | | | |
| -Receivables | (60) | (54) | 18 |
| -Other current assets | (4) | (25) | (30) |
| -Accrued taxes | (55) | 940 | 269 |
| -Other current liabilities | 1 | 46 | (29) |
| Net cash provided from operating activities | 1,155 | 339 | 1,003 |
| Investing Activities: | | | |
| Business acquisitions | (1,032) | (2,294) | (1,719) |
| Property additions | (268) | (2,114) | (1,005) |
| Change in construction payables | (153) | (57) | 251 |
| Investment in restricted cash | (16) | (733) | (159) |
| Distribution of restricted cash | 34 | 736 | 154 |
| Payments pursuant to LTSAs and for equipment not yet received | (203) | (350) | (82) |
| Other investing activities | 15 | 15 | 22 |
| Net cash used for investing activities | (1,623) | (4,797) | (2,538) |
| Financing Activities: | | | |
| Increase (decrease) in notes payable, net | (104) | 73 | (58) |
| Proceeds — | | | |
| Capital contributions | — | 1,850 | 646 |
| Senior notes | 525 | 2,831 | 1,650 |
| Other long-term debt | 43 | 65 | 402 |
| Redemptions — | | | |
| Senior notes | (500) | (200) | (525) |
| Other long-term debt | (18) | (86) | (4) |
| Distributions to noncontrolling interests | (119) | (57) | (18) |
| Capital contributions from noncontrolling interests | 80 | 682 | 341 |
| Purchase of membership interests from noncontrolling interests | (59) | (129) | — |
| Payment of common stock dividends | (317) | (272) | (131) |
| Other financing activities | (33) | (30) | (13) |
| Net cash provided from (used for) financing activities | (502) | 4,727 | 2,290 |
| Net Change in Cash and Cash Equivalents | (970) | 269 | 755 |
| Cash and Cash Equivalents at Beginning of Year | 1,099 | 830 | 75 |

| | | | |
|---|---|---|---|
| Cash and Cash Equivalents at End of Year | $129 | $1,099 | $830 |
| Supplemental Cash Flow Information: | | | |
| Cash paid (received) during the period for — | | | |
| Interest (net of $11, $44, and $14 capitalized, respectively) | $189 | $89 | $74 |
| Income taxes (net of refunds and investment tax credits) | (487 ) | 116 | (518 ) |
| Noncash transactions — | | | |
| Accrued property additions at year-end | 32 | 251 | 257 |
| Accrued acquisitions at year-end | — | 461 | — |

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

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CONSOLIDATED BALANCE SHEETS
At December 31, 2017 and 2016
Southern Power Company and Subsidiary Companies 2017 Annual Report

| Assets | 2017 | 2016 |
|---|---|---|
| | (in millions) | |
| Current Assets: | | |
| Cash and cash equivalents | $129 | $1,099 |
| Receivables — | | |
| Customer accounts receivable | 117 | 102 |
| Affiliated | 50 | 57 |
| Other | 98 | 34 |
| Materials and supplies | 278 | 337 |
| Prepaid income taxes | 50 | 74 |
| Other current assets | 36 | 54 |
| Total current assets | 758 | 1,757 |
| Property, Plant, and Equipment: | | |
| In service | 13,755 | 12,728 |
| Less: Accumulated provision for depreciation | 1,910 | 1,484 |
| Plant in service, net of depreciation | 11,845 | 11,244 |
| Construction work in progress | 511 | 398 |
| Total property, plant, and equipment | 12,356 | 11,642 |
| Other Property and Investments: | | |
| Intangible assets, net of amortization of $47 and $22 at December 31, 2017 and December 31, 2016, respectively | 411 | 436 |
| Total other property and investments | 411 | 436 |
| Deferred Charges and Other Assets: | | |
| Prepaid LTSAs | 118 | 101 |
| Accumulated deferred income taxes | 925 | 594 |
| Income taxes receivable, non-current | 72 | 11 |
| Other deferred charges and assets | 566 | 628 |
| Total deferred charges and other assets | 1,681 | 1,334 |
| Total Assets | $15,206 | $15,169 |

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

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CONSOLIDATED BALANCE SHEETS
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| Liabilities and Stockholders' Equity | 2017 | 2016 |
|---|---|---|
| | (in millions) | |
| Current Liabilities: | | |
| Securities due within one year | $770 | $560 |
| Notes payable | 105 | 209 |
| Accounts payable — | | |
| Affiliated | 102 | 88 |
| Other | 103 | 278 |
| Accrued taxes — | | |
| Accrued income taxes | — | 148 |
| Other accrued taxes | 4 | 7 |
| Acquisitions payable | 5 | 461 |
| Other current liabilities | 143 | 152 |
| Total current liabilities | 1,232 | 1,903 |
| Long-Term Debt: | | |
| Senior notes — | | |
| 1.50% due 2018 | — | 350 |
| 1.95% due 2019 | 600 | 600 |
| 2.375% due 2020 | 300 | 300 |
| 2.50% due 2021 | 300 | 300 |
| 1.00% due 2022 | 720 | 632 |
| 1.85% to 5.25% due 2023-2046 | 2,664 | 2,592 |
| Other long-term debt — | | |
| Variable rate (1.88% at 12/31/17) due 2018 | — | 320 |
| Variable rate (2.18% at 12/31/17) due 2020 | 525 | — |
| Variable rate (3.75% at 1/1/17) due 2032-2036 | — | 15 |
| Unamortized debt premium (discount), net | (10) | (12) |
| Unamortized debt issuance expense | (28) | (29) |
| Long-term debt | 5,071 | 5,068 |
| Deferred Credits and Other Liabilities: | | |
| Accumulated deferred income taxes | 199 | 152 |
| Accumulated deferred ITCs | 1,884 | 1,839 |
| Other deferred credits and liabilities | 322 | 368 |
| Total deferred credits and other liabilities | 2,405 | 2,359 |
| Total Liabilities | 8,708 | 9,330 |
| Redeemable Noncontrolling Interests | — | 164 |
| Common Stockholder's Equity: | | |
| Common stock, par value $0.01 per share — | | |
| Authorized — 1,000,000 shares | | |
| Outstanding — 1,000 shares | — | — |
| Paid-in capital | 3,662 | 3,671 |
| Retained earnings | 1,478 | 724 |
| Accumulated other comprehensive income | (2) | 35 |
| Total common stockholder's equity | 5,138 | 4,430 |
| Noncontrolling Interests | 1,360 | 1,245 |
| Total Stockholders' Equity | 6,498 | 5,675 |

| | | |
|---|---|---|
| Total Liabilities and Stockholders' Equity | $15,206 | $15,169 |
| Commitments and Contingent Matters (See notes) | | |

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

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CONSOLIDATED STATEMENTS OF STOCKHOLDERS' EQUITY
For the Years Ended December 31, 2017, 2016, and 2015
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| | Number of Common Shares Issued | Common Stock | Paid-In Capital | Retained Earnings | Accumulated Other Comprehensive Income | Total Common Stockholder's Equity | Noncontrolling Interests[(a)] | Total |
|---|---|---|---|---|---|---|---|---|
| | (in millions) | | | | | | | |
| Balance at December 31, 2014 | — | $ — | $1,176 | $ 573 | $ 3 | $ 1,752 | $ 219 | $1,971 |
| Net income attributable to Southern Power | — | — | — | 215 | — | 215 | — | 215 |
| Capital contributions from parent company | — | — | 646 | — | — | 646 | — | 646 |
| Other comprehensive income | — | — | — | — | 1 | 1 | — | 1 |
| Cash dividends on common stock | — | — | — | (131) | — | (131) | — | (131) |
| Capital contributions from noncontrolling interests | — | — | — | — | — | — | 567 | 567 |
| Distributions to noncontrolling interests | — | — | — | — | — | — | (17) | (17) |
| Net loss attributable to noncontrolling interests | — | — | — | — | — | — | 12 | 12 |
| Balance at December 31, 2015 | — | — | 1,822 | 657 | 4 | 2,483 | 781 | 3,264 |
| Net income attributable to Southern Power | — | — | — | 338 | — | 338 | — | 338 |
| Capital contributions from parent company | — | — | 1,850 | — | — | 1,850 | — | 1,850 |
| Other comprehensive income | — | — | — | — | 31 | 31 | — | 31 |
| Cash dividends on common stock | — | — | — | (272) | — | (272) | — | (272) |
| Capital 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 | — | — | (1) | 1 | — | — | — | — |
| Balance at December 31, 2016 | — | — | 3,671 | 724 | 35 | 4,430 | 1,245 | 5,675 |
| Net income attributable to Southern Power | — | — | — | 1,071 | — | 1,071 | — | 1,071 |
| Capital contributions from parent company | — | — | (2) | — | — | (2) | — | (2) |
| Other comprehensive income | — | — | — | — | (10) | (10) | — | (10) |
| Cash dividends on common | — | — | — | (317) | — | (317) | — | (317) |

| | | | | | | | |
|---|---|---|---|---|---|---|---|
| stock | | | | | | | |
| Other comprehensive income transfer from SCS [b] | — | — | — | (27) | (27) | — | (27) |
| Capital 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 | — | (7) | — | — | (7) | — | (7) |
| Balance at December 31, 2017 | $ — | $ 3,662 | $ 1,478 | $ (2) | $ 5,138 | $ 1,360 | $ 6,498 |

(a) Excludes redeemable noncontrolling interests. See Note 10 to the financial statements under "Noncontrolling Interests" for additional information.

(b) In connection with the Company becoming a participant to the Southern Company qualified pension plan and other postretirement benefit plan, $27 million of other comprehensive income, net of tax of $9 million, was transferred from SCS.

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

NOTES TO FINANCIAL STATEMENTS
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1. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES
General
Southern Power Company is a wholly-owned subsidiary of Southern Company, which is also the parent company of four traditional electric operating companies, Southern Company Gas (as of July 1, 2016), SCS, 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 Company and its subsidiaries (the Company) develop, construct, acquire, own, and manage power generation assets, including renewable energy projects, and sell electricity at market-based rates in the wholesale market. Southern Company Gas distributes natural gas through utilities in seven states and is involved in several other complementary businesses including gas marketing services, wholesale gas services, and gas midstream operations. SCS, the system service company, provides, at cost, specialized services to Southern Company and its subsidiary companies.
Effective in December 2017, 538 employees transferred from SCS to the Company. The Company became obligated for related employee costs including pension, other postretirement benefits, and stock-based compensation and has recognized the respective balance sheet assets and liabilities, including AOCI impacts, in its balance sheet at December 31, 2017. Prior to the transfer of employees, the Company's agreements with SCS provided for employee services rendered at amounts in compliance with FERC regulations. The Company adopted the same compensation and benefits plans that SCS has and, therefore, future expenses are not expected to be materially different on a per employee basis.
The preparation of consolidated 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 consolidated financial statements have been reclassified to conform to the current year presentation.
The consolidated financial statements include the accounts of Southern Power Company and its wholly-owned and majority-owned subsidiaries. Intercompany accounts and transactions have been eliminated in consolidation.
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.
The Company has completed the evaluation of all revenue streams and determined that the adoption of ASC 606 will not change the current timing or amounts of revenue recognized in the Company's financial statements. Some contractual arrangements, such as certain capacity and energy payments, are excluded from the scope of ASC 606 and included in the scope of the current leasing guidance or the current derivative guidance.
The new standard is effective for reporting periods beginning after December 15, 2017. The Company applied the modified retrospective method of adoption effective January 1, 2018. The 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. The adoption of ASC 606 did not result in a cumulative 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. ASU 2016-02 is effective for fiscal years beginning after December 15, 2018 and the Company will adopt the new standard effective January 1, 2019.

The 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, the Company has substantially completed a detailed inventory and analysis of its leases where the majority relate to land leases for its renewable generation facilities. While the Company has not yet determined the ultimate impact, adoption of ASU 2016-02 is expected to have a significant impact on the Company's balance sheet for lessee arrangements.

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. The Company adopted ASU 2016-18 effective January 1, 2018 with no material 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 other income (expense) in the income statement. Additionally, only the service cost component related to construction labor is eligible for capitalization, when applicable. The Company adopted ASU 2017-07 which is effective for periods beginning after December 15, 2017; however, since the Company became a sponsor of a qualified pension plan and postretirement benefit plan in December 2017, no retrospective presentation of net periodic benefits costs for 2016 or 2017 is required. See Note 2 for additional information.

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. The Company adopted ASU 2017-12 effective January 1, 2018 with no material impact on its financial statements.

Affiliate Transactions

Total revenues from all PPAs with affiliates, included in wholesale revenue affiliates on the consolidated statements of income, were $233 million, $258 million, and $219 million for the years ended December 31, 2017, 2016, and 2015, respectively. Included within these revenues were affiliate PPAs accounted for as operating leases, which totaled $81 million for the year ended December 31, 2017 and $109 million for each of the years ended December 31, 2016 and 2015.

The Company has an agreement with SCS under which the following services are rendered to the Company at amounts in compliance with FERC regulation: general and design engineering, purchasing, accounting, finance and treasury, tax, information technology, marketing, auditing, insurance and pension administration, human resources, systems and procedures, digital wireless communications, labor, and other services with respect to business and operations, construction management, and transactions associated with the Southern Company system's fleet of generating units. Prior to December 2017, the Company did not have employees and thus all employee-related charges were rendered at amounts in compliance with FERC regulation under agreements with SCS. Costs for all of these services from SCS totaled $218 million, $193 million, and $146 million for the years ended December 31, 2017, 2016, and 2015, respectively. Of these costs, $192 million, $173 million, and $138 million for the years ended December 31, 2017, 2016, and 2015, respectively, were charged to other operations and maintenance expenses; the remainder was primarily capitalized to property, plant, and equipment. Cost allocation methodologies used by SCS prior to the repeal of the Public Utility Holding Company Act of 1935, as amended, were approved by the SEC. Subsequently, additional cost allocation methodologies have been reported to the FERC and management believes they are reasonable. The FERC permits services to be rendered at cost by system service companies.

Total power purchased from affiliates through the power pool, included in purchased power in the consolidated statements of income, totaled $27 million for the year ended December 31, 2017 and $21 million for each of the years ended December 31, 2016 and 2015.

The Company also has several agreements with SCS for transmission services. Transmission services purchased from SCS totaled $13 million for the year ended December 31, 2017 and $11 million for each of the years ended December 31, 2016 and 2015 and were charged to other operations and maintenance in the consolidated statements of income. All charges were billed to the Company based on the Southern Company Open Access Transmission Tariff as filed with the FERC.

Prior to Southern Company's acquisition of Southern Company Gas, SCS, as agent for the Company, had agreements with various subsidiaries of Southern Company Gas to purchase natural gas. Natural gas purchases made by the Company from Southern Company Gas' subsidiaries were $119 million for the year ended December 31, 2017 and $17 million for the period subsequent to

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Southern Company's acquisition of Southern Company Gas through December 31, 2016, and are included in fuel expense on the consolidated statements of income.

On September 1, 2016, Southern Company Gas acquired a 50% equity interest in Southern Natural Gas Company, L.L.C. (SNG). Prior to completion of the acquisition, SCS, as agent for the Company, had entered into a long-term interstate natural gas transportation agreement with SNG. The interstate transportation service provided to the Company by SNG pursuant to this agreement is governed by the terms and conditions of SNG's natural gas tariff and is subject to FERC regulation. Transportation costs under this agreement were $25 million for the year ended December 31, 2017 and $7 million for the period subsequent to Southern Company Gas' investment in SNG through December 31, 2016.

The Company and the traditional electric operating companies may jointly enter into various types of wholesale energy, natural gas, and certain other contracts, either directly or through SCS as agent. Each participating company may be jointly and severally liable for the obligations incurred under these agreements. See "Revenues" herein for additional information. The Company and the traditional electric operating companies generally settle amounts related to the above transactions on a monthly basis in the month following the performance of such services or the purchase or sale of electricity.

Acquisition Accounting

The Company may acquire generation assets as part of its overall growth strategy. At the time of an acquisition, the Company will assess if these assets and activities meet the definition of a business. For acquisitions that meet the definition of a business, the Company includes operating results from the date of acquisition in its consolidated financial statements. The purchase price, including any contingent consideration, is allocated based on the fair value of the identifiable assets acquired and liabilities assumed (including any intangible assets). Assets acquired that do not meet the definition of a business are accounted for as an asset acquisition.

The purchase price of each asset acquisition is allocated based on the relative fair value of assets acquired. Determining the fair value of assets acquired and liabilities assumed requires management judgment and the Company may engage independent valuation experts to assist in this process. Fair values are determined by using market participant assumptions, and typically include the timing and amounts of future cash flows, incurred construction costs, the nature of acquired contracts, discount rates, power market prices, and expected asset lives. Any due diligence or transition costs incurred by the Company for potential or successful acquisitions are expensed as incurred. Contingent consideration primarily relates to fixed amounts due to the seller once the facility is placed in service. For contingent consideration with variable payments, the Company fair values the arrangement with any changes recorded in the consolidated statements of income. See Note 8 for additional fair value information.

Revenues

The Company sells capacity at rates specified under contractual terms for long-term PPAs. These PPAs are generally accounted for as operating leases, non-derivatives, or normal sale derivatives. Capacity revenues from PPAs classified as operating leases are recognized on a straight-line basis over the term of the agreement. Capacity revenues from PPAs classified as non-derivatives or normal sales are recognized at the lesser of the levelized amount or the amount billable under the contract over the respective contract periods. When multiple contracts exist with the same counterparty, the revenues from each contract are accounted for as separate arrangements. All capacity revenues are included in wholesale revenues.

The Company may also enter into contracts to sell short-term capacity in the wholesale electricity markets. These sales are generally classified as mark-to-market derivatives and net unrealized gains (losses) on such contracts are recorded in wholesale revenues. See Note 9 for additional information.

Energy revenues and other contingent revenues are recognized in the period the energy is delivered or the service is rendered. Transmission revenues and other fees are recognized as earned as other operating revenues. See "Financial Instruments" herein for additional information.

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Significant portions of the Company's revenues have been derived from certain customers pursuant to PPAs. The following table shows the percentage of total revenues for the Company's top three customers for each of the years presented:

| | 2017 | 2016 | 2015 |
|---|---|---|---|
| Georgia Power | 11.3% | 16.5% | 15.8% |
| Duke Energy Corporation | 6.7 % | 7.8 % | 8.2 % |
| Morgan Stanley Capital Group | 4.5 % | N/A | N/A |
| San Diego Gas & Electric Company | N/A | 5.7 % | N/A |
| Florida Power & Light Company | N/A | N/A | 10.7% |

Fuel Costs
Fuel costs are expensed as the fuel is used. Fuel costs also include emissions allowances which are expensed as the emissions occur.
Development Costs
The Company capitalizes development costs once a project is probable of completion, primarily based on a review of its economics and operational feasibility, as well as status of power off-take agreements and regulatory approvals, if applicable. Capitalized development costs are included in construction work in progress on the consolidated balance sheets. All development costs incurred prior to the determination that a project is probable of completion are expensed as incurred and included in other operations and maintenance expense in the consolidated statements of income. If it is determined that a project is no longer probable of completion, any capitalized development costs are expensed and included in other operations and maintenance expense in the consolidated statements of income.
Income and Other Taxes
The Company uses the liability method of accounting for deferred income taxes and provides deferred income taxes for all significant income tax temporary differences.
Under current tax regulation, certain projects related to the construction of renewable facilities are eligible for federal ITCs. The Company estimates eligible costs which, as they relate to acquisitions, may not be finalized until the allocation of the purchase price to assets has been finalized. The Company applies the deferred method to ITCs as opposed to the flow-through method. Under the deferred method the ITCs are recorded as a deferred credit and amortized to income tax expense over the life of the respective asset. Furthermore, the tax basis of the asset is reduced by 50% of the ITCs received, resulting in a net deferred tax asset. The Company 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 as an income tax benefit based on KWH production. Federal ITCs and PTCs available to reduce income taxes payable were not fully utilized during 2017 and will be carried forward and utilized in future years. The Company recognizes tax positions that are "more likely than not" of being sustained upon examination by the appropriate taxing authorities. See Note 5 for additional information.
Property, Plant, and Equipment
The Company's depreciable property, plant, and equipment consists primarily of generation assets.
Property, plant, and equipment is stated at original cost or acquired fair value. Original cost includes: materials, direct labor incurred by contractors and affiliated companies, and interest capitalized. Interest is capitalized on qualifying projects during the development and construction period. The cost to replace significant items of property defined as retirement units is capitalized. The cost of maintenance, repairs, and replacement of minor items of property is charged to other operations and maintenance expenses as incurred.
When depreciable property, plant, and equipment is retired, or otherwise disposed of in the normal course of business, the applicable cost and accumulated depreciation is removed and a gain or loss is recognized in the consolidated statements of income.
Depreciation

The Company applies component depreciation, where depreciation is computed principally by the straight-line method over the estimated useful life of the asset. Certain generation assets related to natural gas-fired facilities are depreciated on a units-of-

NOTES (continued)
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production basis, using hours or starts, to better match outage and maintenance costs to the usage of, and revenues from, these assets.

The primary assets in property, plant, and equipment are generating facilities, which generally have estimated useful lives as follows:

| Generating facility | Useful life |
|---|---|
| Natural gas | Up to 45 years |
| Biomass | Up to 40 years |
| Solar | Up to 35 years |
| Wind | Up to 30 years |

The Company reviews its estimated useful lives and salvage values on an ongoing basis. The results of these reviews could result in changes which could have a material impact on net income in the near term.

Asset Retirement Obligations

Asset retirement obligations (ARO) are computed as the present value of the estimated ultimate costs for an asset's future retirement and are recorded in the period in which the liability is incurred. The costs are capitalized as part of the related long-lived asset and depreciated over the asset's useful life. In the absence of quoted market prices, AROs are estimated using present value techniques in which estimates of future cash outlays associated with the asset retirements are discounted using a credit-adjusted risk-free rate. Estimates of the timing and amounts of future cash outlays are based on projections of when and how the assets will be retired and the cost of future removal activities. The ARO liability primarily relates to the Company's solar and wind facilities, which are located on long-term land leases requiring the restoration of land at the end of the lease. See Note 11 for acquisitions during 2017 and 2016 which contributed to the increased liability.

Details of the AROs included on the consolidated balance sheets are as follows:

| | 2017 | 2016 |
|---|---|---|
| | (in millions) | |
| Balance at beginning of year | $64 | $ 21 |
| Liabilities incurred | 6 | 42 |
| Accretion | 4 | 1 |
| Cash flow revisions | 4 | — |
| Balance at end of year | $78 | $ 64 |

Long-Term Service Agreements

The Company has entered into LTSAs for the purpose of securing maintenance support for its natural gas-fired generating facilities. The LTSAs cover all planned inspections on the covered equipment, which generally includes the cost of all labor and materials. The LTSAs also obligate the counterparties to cover the costs of unplanned maintenance on the covered equipment subject to limits and scope specified in each contract.

Payments made under the LTSAs prior to the performance of any planned inspections or unplanned capital maintenance are recorded as a prepayment in other current assets and noncurrent assets on the consolidated balance sheets and are recorded as payments pursuant to LTSAs and for equipment not yet received in the statements of cash flows. At the time work is performed, which typically occurs during planned inspections, an appropriate amount is transferred from the prepayment to property, plant, and equipment or charged to expense. The receipt of major parts into materials and supplies inventory prior to planned inspections is treated as a noncash transaction for purposes of the consolidated statements of cash flows.

Impairment of Long-Lived Assets and Intangibles

The Company evaluates long-lived assets and finite-lived intangibles for impairment when events or changes in circumstances indicate that the carrying value of such assets may not be recoverable. The Company's intangible assets consist primarily of certain PPAs acquired, which are amortized over the term of the PPAs, which have a weighted average term of 19 years. The determination of whether an impairment has occurred is based on an estimate of undiscounted future cash flows attributable to the

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assets, as compared with the carrying value of the assets. If the estimate of undiscounted future cash flows is less than the carrying value of the asset, the fair value of the asset is determined and a loss is recorded.

Amortization expense for acquired PPAs was $25 million, $10 million, and $3 million for the years ended December 31, 2017, 2016, and 2015, respectively, and is recorded in operating revenues. The estimated annual amortization expense is $25 million for each of the next five years.

Transmission Receivables/Prepayments

As a result of the Company's growth from the acquisition and construction of generating facilities, the Company has transmission receivables and/or prepayments representing the portion of interconnection network and transmission upgrades that will be reimbursed to the Company. Upon completion of the related project, transmission costs are generally reimbursed by the interconnection provider within a five-year period and the receivable/prepayments are reduced as payments or services are received.

Restricted Cash

The Company has restricted cash primarily related to certain acquisitions and construction projects. The aggregate amount of restricted cash at December 31, 2017 and 2016 was $11 million and $13 million, respectively.

Cash and Cash Equivalents

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

Materials and Supplies

Materials and supplies include the average cost of generating plant materials and are recorded as inventory when purchased and then expensed or capitalized to property, plant, and equipment, as appropriate, at weighted average cost when installed. In addition, certain major parts are recorded as inventory when acquired and then capitalized at cost when installed to property, plant, and equipment.

Fuel Inventory

Fuel inventory, which is included in other current assets, includes the cost of oil, natural gas, biomass, and emissions allowances. The Company maintains oil inventory for use at several natural gas generating units. The Company has contracts in place for natural gas storage to support normal operations of the Company's natural gas generating units. The Company also maintains biomass inventory for use at Plant Nacogdoches. Inventory is maintained using the weighted average cost method. Fuel inventory and emissions allowances are recorded at actual cost when purchased and then expensed at weighted average cost as used. Emissions allowances granted by the EPA are included at zero cost.

Financial Instruments

The Company uses derivative financial instruments to limit exposure to fluctuations in interest rates, the prices of certain fuel purchases, electricity purchases and sales, and foreign currency exchange rates. All derivative financial instruments are recognized as either assets or liabilities on the consolidated balance sheets (included in "Other") and are measured at fair value. See Note 8 for additional information regarding fair value. Substantially all of the Company's bulk energy purchases and sales contracts that meet the definition of a derivative are excluded from fair value accounting requirements because they qualify for the "normal" scope exception, and are accounted for under the accrual method. Derivative contracts that qualify as cash flow hedges of anticipated transactions result in the deferral of related gains and losses in AOCI 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 in the financial statement line item where they will eventually settle. Cash flows from derivatives are classified on the statement of cash flows in the same category as the hedged item. See Note 9 for additional information regarding derivatives.

The Company offsets the fair value amounts recognized for multiple derivative instruments executed with the same counterparty under a netting arrangement. Additionally, the Company had no outstanding collateral repayment obligations or rights to reclaim collateral arising from derivative instruments recognized at December 31, 2017 or

2016.

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

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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, certain changes in pension and other postretirement benefit plans, and reclassifications of amounts included in net income. Accumulated OCI (loss) balances, net of tax effects, were as follows:

| | Qualifying Hedges | Pension and Other Postretirement Benefit Plans | Accumulated Other Comprehensive Income (Loss) |
|---|---|---|---|
| | (in millions) | | |
| Balance at December 31, 2016 | $35 | $ — | $ 35 |
| Current period change | (10) | — | (10) |
| Other comprehensive income transfer from SCS(*) | — | (27) | (27) |
| Balance at December 31, 2017 | $25 | $ (27) | $ (2) |

(*) In connection with the Company becoming a participant to the Southern Company qualified pension plan and other postretirement benefit plan, $27 million of OCI, net of tax of $9 million, was transferred from SCS.

Variable Interest Entities

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

The Company has certain wholly-owned subsidiaries that are determined to be VIEs. The Company is considered the primary beneficiary of these VIEs because it controls the most significant activities of the VIEs, including operating and maintaining the respective assets, and has the obligation to absorb expected losses of these VIEs to the extent of its equity interests.

2. RETIREMENT BENEFITS

Effective in December 2017, 538 employees transferred from SCS to the Company. Accordingly, the Company assumed various compensation and benefit plans including a defined benefit, trusteed, pension plan covering substantially all employees. The qualified pension plan is funded in accordance with requirements of the Employee Retirement Income Security Act of 1974, as amended (ERISA). With the transfer of employees, the Company assumed the related benefit obligations from SCS of $139 million for the qualified pension plan (along with trust assets of $138 million) and $11 million for other postretirement benefit plans, together with $36 million in prior service costs and net gains/losses that are in OCI. In 2018, the Company will also begin providing certain defined benefits under a non-qualified pension plan for a select group of management and highly compensated employees. No obligation related to these benefits was assumed in the employee transfer; however, obligations under the non-qualified pension plan for future services rendered by employees will be recognized beginning in 2018 and ultimately funded on a cash basis. In addition, the Company provides certain medical care and life insurance benefits for retired employees through other postretirement benefit plans that are to be funded on a cash basis.

Prior to the transfer of employees in December 2017, substantially all expenses charged by SCS, including pension and other postretirement benefit costs, were recorded in other operations and maintenance expense. Beginning in 2018, in connection with the adoption of ASU 2017-07, the service cost component of pension and postretirement benefit costs will be recorded in other operations and maintenance expense while the non-service cost components of pension and postretirement benefit costs will be recorded in other income (expense). See Note 1 under "General" for additional information.

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Actuarial Assumptions
The weighted average rates assumed in the actuarial calculations used to determine the benefit obligations for the pension and other postretirement plans as of the December 31, 2017 measurement date are presented below.

| Assumptions used to determine benefit obligations: | 2017 |
|---|---|
| Pension plans | |
| Discount rate | 3.94% |
| Annual salary increase | 4.46 |
| Other postretirement benefit plans | |
| Discount rate | 3.81% |
| Annual salary increase | 4.46 |

In determining the amount of pension cost to be recognized in 2018, the Company estimates the expected rate of return on pension plan assets using a financial model to project the expected return on the current investment portfolio. The analysis projects an expected rate of return on each of the different asset classes in order to arrive at the expected return on the entire portfolio relying on the 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), the trust's target asset allocation, an anticipated inflation rate, and the projected impact of a periodic rebalancing of the trust's portfolio.
An additional assumption used in measuring the accumulated other postretirement benefit obligations (APBO) is 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 have an immaterial effect on the APBO at December 31, 2017.
Pension Plan
The total accumulated benefit obligation for the pension plan was $111 million at December 31, 2017. The projected benefit obligation for the pension plan was $139 million and the fair value of plan assets was $138 million at December 31, 2017.
Presented below are the amounts included in AOCI at December 31, 2017 related to the Company's pension plan that had not yet been recognized in net periodic pension cost, along with the estimated amortization of such amounts for 2018.

| | 2017 | Estimated Amortization in 2018 |
|---|---|---|
| | (in millions) | |
| Prior service cost | $ 1 | $ — |
| Net (gain) loss | 32 | 2 |
| AOCI | $ 33 | |

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Future benefit payments reflect expected future service and are estimated based on assumptions used to measure the projected benefit obligation for the pension plan. At December 31, 2017, estimated benefit payments average approximately $4 million each year for the next five years, and for the five-year period from 2023 to 2027 estimated benefit payments are $27 million.

Other Postretirement Benefits

The APBO for the other postretirement benefit plan at December 31, 2017 is $11 million. Amounts recognized in the balance sheet at December 31, 2017 related to the Company's other postretirement benefit plan consist of the following:

| | 2017 (in millions) |
|---|---|
| Employee benefit obligations (included in other deferred credits and liabilities) | $ (11 ) |
| AOCI | 3 |

Presented below are the amounts included in AOCI at December 31, 2017 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.

| | 2017 | Estimated Amortization in 2018 |
|---|---|---|
| | (in millions) | |
| Net (gain) loss | $ 3 | $ — |
| AOCI | $ 3 | |

Future benefit payments, which include any prescription drug benefits, and any offset from drug subsidiary receipts, are immaterial for each of the years 2018-2027.

Benefit Plan Assets

Pension plan assets are managed and invested in accordance with all applicable requirements, including ERISA and the Internal Revenue Code of 1986, as amended. The Company's investment policies for the pension plan cover a diversified mix of assets, including equity and fixed income securities, real estate, and private equity. Derivative instruments are used primarily to gain efficient exposure to the various asset classes and as hedging tools. The Company minimizes the risk of large losses primarily through diversification but also monitors and manages other aspects of risk.

The composition of the Company's pension plan assets as of December 31, 2017, along with the targeted mix of assets for the plan, is presented below:

| | Target | 2017 |
|---|---|---|
| Pension plan assets: | | |
| Domestic equity | 26 % | 31 % |
| International equity | 25 | 25 |
| Fixed income | 23 | 24 |
| Special situations | 3 | 1 |
| Real estate investments | 14 | 13 |
| Private equity | 9 | 6 |
| Total | 100 % | 100 % |

The investment strategy for plan assets related to the Company's qualified pension plan is to be broadly diversified across major asset classes. The asset allocation is established after consideration of various factors that affect the assets and liabilities of the pension plan including, but not limited to, historical and expected returns and interest rates, volatility, correlations of asset classes, the current level of assets and liabilities, and the assumed growth in assets and liabilities. Because a significant portion of the liability of the pension plan is long-term in nature, the assets are invested consistent with long-term investment expectations for return and risk. To manage the actual asset class exposures relative to the target asset allocation, the Company employs a formal rebalancing program. As additional risk management, external investment managers and service providers are subject to written guidelines to ensure appropriate and prudent investment practices. Management believes the portfolio is well-diversified with no significant concentrations of risk.

Investment Strategies

Detailed below is a description of the investment strategies for each major asset category for the pension benefit plan disclosed above:

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

Benefit Plan Asset Fair Values

Following are the fair value measurements for the pension plan assets as of December 31, 2017. The fair values presented are prepared in accordance with GAAP. For purposes of determining the fair value of the pension plan assets and the appropriate level designation, management relies on information provided by the plan's trustee. This information is reviewed and evaluated by management with changes made to the trustee information as appropriate.

Valuation methods of the primary fair value measurements disclosed in the following tables are as follows:

- Domestic and international equity. Investments in equity securities such as common stocks, American depositary receipts, and real estate investment trusts that trade on a public exchange are classified as Level 1 investments and are valued at the closing price in the active market. Equity investments with unpublished prices (i.e. pooled funds) are valued as Level 2, when the underlying holdings used to value the investment are comprised of Level 1 or Level 2 equity securities.
- Fixed income. Investments in fixed income securities are generally classified as Level 2 investments and are valued based on prices reported in the market place. Additionally, the value of fixed income securities takes into consideration certain items such as broker quotes, spreads, yield curves, interest rates, and discount rates that apply to the term of a specific instrument.
- Real estate investments, private equity, and special situations investments. Investments in real estate, private equity, and special situations are generally classified as Net Asset Value as a Practical Expedient, since the underlying assets typically do not have publicly available observable inputs. The fund manager values the assets using various inputs and techniques depending on the nature of the underlying investments. Techniques may include purchase multiples for comparable transactions, comparable public company trading multiples, discounted cash flow analysis, prevailing market capitalization rates, recent sales of comparable investments, and independent third-party appraisals. The fair value of partnerships is determined by aggregating the value of the underlying assets less liabilities.

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The fair values of pension plan assets as of December 31, 2017 are presented below. These fair value measurements exclude cash, receivables related to investment income, pending investments sales, and payables related to pending investment purchases.

| | 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(*) | $28 | $ 13 | $ — | $ — | $41 |
| International equity(*) | 18 | 16 | — | — | 34 |
| Fixed income: | | | | | |
| U.S. Treasury, government, and agency bonds | — | 10 | — | — | 10 |
| Corporate bonds | — | 14 | — | — | 14 |
| Pooled funds | — | 8 | — | — | 8 |
| Cash equivalents and other | 2 | — | — | — | 2 |
| Real estate investments | 5 | — | — | 14 | 19 |
| Special situations | — | — | — | 2 | 2 |
| Private equity | — | — | — | 8 | 8 |
| Total | $53 | $ 61 | $ — | $ 24 | $138 |

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

## 3. CONTINGENCIES AND REGULATORY MATTERS

### General Litigation Matters

The Company is subject to certain claims and legal actions arising in the ordinary course of business. In addition, the Company's business activities are subject to extensive governmental regulation related to public health and the environment. 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 and alleged exposure to hazardous materials, and/or requests for injunctive relief in connection with such matters. The ultimate outcome of such pending or potential litigation against the Company 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 the Company's financial statements.

During 2015, the Company indirectly acquired a 51% membership interest in RE Roserock LLC (Roserock), the owner of the Roserock facility in Pecos County, Texas, which was under construction by Recurrent Energy, LLC and was subsequently placed in service in November 2016. Prior to placing the facility in service, certain solar panels were damaged during installation. While the facility currently is generating energy consistent with operational expectations and PPA obligations, the Company is pursuing remedies under its insurance policies and other contracts to repair or replace these solar panels. In connection therewith, the Company is withholding payments of approximately $26 million from the construction contractor, who has placed a lien on the Roserock facility for the same amount. The amounts withheld are included in other accounts payable and other current liabilities on the Company's consolidated balance sheets. On May 18, 2017, Roserock filed a lawsuit in the state district court in Pecos County, Texas, against XL Insurance America, Inc. (XL) and North American Elite Insurance Company (North American Elite) seeking recovery from an insurance policy for damages resulting from a hail storm and certain installation practices by the construction contractor, McCarthy Building Companies, Inc. (McCarthy). On May 19, 2017, Roserock filed a separate lawsuit against McCarthy in the state district court in Travis County, Texas alleging breach of contract and breach of warranty for the damages sustained at the Roserock facility, which has since been moved to the U.S. District Court for the Western District of Texas. On May 22, 2017, McCarthy filed a counter lawsuit against Roserock, Array Technologies, Inc., Canadian Solar (USA), Inc., XL, and North American Elite in the U.S. District Court for the Western District of Texas alleging, among other things,

NOTES (continued)
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breach of contract, and requesting foreclosure of mechanic's liens against Roserock. On July 18, 2017, the U.S. District Court for the Western District of Texas consolidated the two pending lawsuits. On December 11, 2017, the U.S. District Court for the Western District of Texas dismissed McCarthy's claims against Canadian Solar (USA), Inc. and dismissed cross-claims that XL and North American Elite had sought to bring against Roserock. The Company intends to vigorously pursue and defend these matters, the ultimate outcome of which cannot be determined at this time.

FERC Matters

The Company and certain of its generation subsidiaries are subject to regulation by the FERC. The Company has authority from the FERC to sell electricity at market-based rates. Since 2008, that authority, for certain balancing authority areas, has been conditioned on compliance with the requirements of an energy auction, which the FERC found to be tailored mitigation that addresses potential market power concerns. In accordance with FERC regulations governing such authority, the traditional electric operating companies and the Company 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 the Company'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 the Company 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 the Company filed a request for rehearing and filed their response with the FERC in 2015.

In December 2016, the traditional electric operating companies and the Company 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 the Company'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 the Company'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 the Company's June 29, 2017 triennial updated market power analysis. The FERC directed the traditional electric operating companies and the Company 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 the Company 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.

4. JOINT OWNERSHIP AGREEMENTS

The Company is a 65% owner of Plant Stanton A, a natural gas-fired combined-cycle unit with a nameplate capacity of 659 MWs. The unit is co-owned by the Orlando Utilities Commission (28%), the Florida Municipal Power Agency (3.5%), and the Kissimmee Utility Authority (3.5%). The Company has a service agreement with SCS whereby SCS is responsible for the operation and maintenance of Plant Stanton A. As of December 31, 2017, $155 million was recorded in plant in service with associated accumulated depreciation of $55 million. These amounts represent the Company's share of total plant assets and each owner is responsible for providing its own financing. The Company's proportionate share of Plant Stanton A's operating expense is included in the corresponding operating expenses in the consolidated statements of income.

5. INCOME TAXES

On behalf of the Company, Southern Company files a consolidated federal income tax return and various state income tax returns, some of which are combined, unitary, or consolidated. Under a joint consolidated income tax allocation agreement, each Southern Company subsidiary's current and deferred tax expense is computed on a stand-alone basis and no subsidiary is allocated more current expense than would be paid if it filed a separate income tax return. In accordance with IRS regulations, each company is jointly and severally liable for the federal tax liability.

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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. The 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 cannot be determined at this time.
Current and Deferred Income Taxes
Details of income tax provisions are as follows:

| | 2017 | 2016 | 2015 |
|---|---|---|---|
| | (in millions) | | |
| Federal — | | | |
| Current (*) | $(566) | $928 | $12 |
| Deferred (*) | (312) | (1,098) | 10 |
| | (878) | (170) | 22 |
| State — | | | |
| Current | (110) | (60) | (32) |
| Deferred | 49 | 35 | 31 |
| | (61) | (25) | (1) |
| Total | $(939) | $(195) | $21 |

(*) ITCs and PTCs generated in the current tax year and carried forward from prior tax years that cannot be utilized in the current tax year are reclassified from current to deferred taxes in federal income tax expense above. ITCs and PTCs reclassified in this manner include $316 million for 2017, $1.13 billion for 2016, and $246 million for 2015. These ITCs and PTCs are included in the following table of temporary differences as unrealized tax credits.

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The tax effects of temporary differences between the carrying amounts of assets and liabilities in the financial statements and their respective tax bases, which give rise to deferred tax assets and liabilities, are as follows:

| | 2017 | 2016 |
|---|---|---|
| | (in millions) | |
| Deferred tax liabilities — | | |
| Accelerated depreciation and other property basis differences | $1,922 | $2,440 |
| Levelized capacity revenues | 26 | 28 |
| Other | 6 | 27 |
| Total deferred income tax liabilities | 1,954 | 2,495 |
| Deferred tax assets — | | |
| Federal effect of state deferred taxes | 42 | 53 |
| Basis difference on ITCs | 184 | 292 |
| Alternative minimum tax carryforward | 21 | 15 |
| Unrealized tax credits | 2,002 | 1,685 |
| Federal net operating loss (NOL) | 333 | 808 |
| Deferred state tax assets | 77 | 60 |
| Other partnership basis differences | 24 | 16 |
| Other | 10 | 8 |
| Total deferred income tax assets | 2,693 | 2,937 |
| Valuation Allowance | (13) | — |
| Net deferred income tax assets | 2,680 | 2,937 |
| Total deferred income tax asset (liability) | $726 | $442 |
| | | |
| Recognized in the consolidated balance sheets: | | |
| Accumulated deferred income taxes – assets | $925 | $594 |
| Accumulated deferred income taxes – liability | $(199) | $(152) |

Deferred tax liabilities are primarily the result of property-related timing differences, which increased due to bonus depreciation. However, the implementation of the Tax Reform Legislation significantly reduced the amount of accumulated deferred income taxes at December 31, 2017.

Deferred tax assets consist primarily of timing differences related to the carryforward of unrealized federal ITCs, PTCs, net operating loss, and net basis differences on federal ITCs.

Tax Credit Carryforwards

At December 31, 2017, the Company had federal ITC and PTC carryforwards, which are expected to result in $2.0 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 2036 but are also expected to be fully utilized by 2027. The acquisition of additional renewable projects could further delay the utilization of existing tax credit carryforwards. The ultimate outcome of these matters cannot be determined at this time.

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 expire in 2037 but is expected to be fully utilized by 2019. The ultimate outcome of this matter cannot be determined at this time.

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The Company had state NOL carryforwards of approximately $1.3 billion at December 31, 2017, which will expire from 2029 to 2035. These carryforwards resulted in deferred tax assets of approximately $61 million as of December 31, 2017. The state NOL carryforwards by state jurisdiction were as follows:

| Jurisdiction | Approximate NOL Carryforwards | Approximate Net State Income Tax Benefit | Tax Year NOL Expires |
|---|---|---|---|
| | (in millions) | | |
| Oklahoma | $ 978 | $ 46 | 2035 |
| Florida | 283 | 12 | 2033 |
| South Carolina | 48 | 2 | 2035 |
| Other states | 23 | 1 | 2029-2035 |
| Balance at year end | $ 1,332 | $ 61 | |

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 | (22.2 ) | (9.1 ) | (0.3 ) |
| Amortization of ITC | (31.8 ) | (20.6 ) | (5.0 ) |
| ITC basis difference | (10.0 ) | (89.0 ) | (21.5) |
| Production tax credits | (72.5 ) | (23.3 ) | (0.6 ) |
| Tax Reform Legislation | (416.1) | — | — |
| Noncontrolling interests | (8.6 ) | (6.2 ) | (1.7 ) |
| Other | 0.5 | 4.6 | 2.5 |
| Effective income tax rate (benefit) | (525.7)% | (108.6)% | 8.4 % |

The Company's effective tax rate decreased in 2017 primarily due to the Tax Reform Legislation. The decrease in 2016 was primarily due to changes in federal ITCs and PTCs.

The Company's deferred federal ITCs are amortized to income tax expense over the life of the respective asset. ITCs amortized in this manner amounted to $57 million in 2017, $37 million in 2016, and $19 million in 2015. Also, the Company received cash related to federal ITCs under the renewable energy incentives of $162 million for the year ended December 31, 2015. While no cash was received related to these incentives in 2017 or 2016, the Company recognized tax credits. Furthermore, the tax basis of the asset is reduced by 50% of the ITCs received, resulting in a net deferred tax asset. The Company 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. The tax benefit of PTCs reduced income tax expense by $129 million in 2017, $42 million in 2016 and $1 million in 2015. See "Unrecognized Tax Benefits" herein for further 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 the 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.

NOTES (continued)
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Unrecognized Tax Benefits

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

| | 2017 | 2016 | 2015 |
|---|---|---|---|
| | (in millions) | | |
| Balance at beginning of year | $17 | $8 | $ 5 |
| Tax positions increase from current periods | — | 17 | 9 |
| Tax positions decrease from prior periods | (17 ) | (8 ) | (6 ) |
| Balance at end of year | $— | $17 | $ 8 |

The increase in unrecognized tax benefits from current periods for all years presented, and the decrease from prior periods for all years presented, primarily relate to federal income tax benefits from deferred ITCs and would all impact the Company's effective tax rate, if recognized. The impact on the effective tax rate is determined based on the amount of ITCs which are uncertain.

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

It is reasonably possible that the amount of the unrecognized tax benefits could change within 12 months. The settlement of federal and state audits could impact the balances. 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. The audits for the Company's state income tax returns have either been concluded, or the statute of limitations has expired, for years prior to 2011.

6. FINANCING

Southern Power Company's senior notes, bank term loans, commercial paper, and Facility (as defined herein) are unsecured senior indebtedness, which rank equally with all other unsecured and unsubordinated debt of Southern Power Company. The Company's subsidiaries are not issuers, borrowers, or obligors, as applicable, under the senior notes, borrowings from financial institutions, commercial paper, or the Facility. The senior notes, borrowings from financial institutions, commercial paper, and the Facility are effectively subordinated to any future secured debt of Southern Power Company and any potential claims of creditors of the Company's subsidiaries. As of December 31, 2017, the Company had no secured debt.

Securities Due Within One Year

At December 31, 2017, the Company had $420 million in term loans and $350 million of senior notes due within one year. At December 31, 2016, the Company had a $60 million term loan, $500 million of senior notes, and $1 million of long-term notes due within one year.

Maturities of long-term debt for the next five years are as follows:

| | December 31, 2017 |
|---|---|
| | (in millions) |
| 2018 | $ 770 |
| 2019 | 600 |
| 2020 | 825 |
| 2021 | 300 |
| 2022(*) | 677 |

(*) Represents euro-denominated debt at the U.S. dollar denominated hedge settlement amount.

Senior Notes

In November 2017, the Company issued $525 million aggregate principal amount of Series 2017A Floating Rate Senior Notes due December 20, 2020, which bear interest based on three-month LIBOR. The net proceeds were used to redeem all of the $500 million aggregate principal amount of Series 2015D 1.85% Senior Notes due December 1, 2017 and to repay a portion of the Company's outstanding short-term debt.

NOTES (continued)
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At December 31, 2017 and 2016, the Company had $5.5 billion and $5.3 billion of senior notes outstanding, respectively, which included senior notes due within one year.

Other Long-Term Notes

In September 2017, the Company 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 additional $40 million of proceeds were used to repay existing indebtedness and for other general corporate purposes.

At December 31, 2017, outstanding term loans were included in securities due within one year.

The outstanding term loans as of December 31, 2017 have a covenant that limits debt levels to 65% of total capitalization, as defined in the agreements. For purposes of this definition, debt excludes any project debt incurred by certain subsidiaries of the company to the extent such debt is non-recourse to the company, and capitalization excludes the capital stock or other equity attributable to such subsidiary.

At December 31, 2017, the Company was in compliance with its debt limits.

Bank Credit Arrangements

Company Credit Facilities

At December 31, 2017, the Company had a committed credit facility (Facility) of $750 million expiring in 2022, of which $22 million has been used for letters of credit and $728 million remains unused. In May 2017, the Company amended the Facility, which, among other things, extended the maturity date from 2020 to 2022 and increased the Company's borrowing ability under the Facility to $750 million from $600 million. Proceeds from the Facility may be used for working capital and general corporate purposes as well as liquidity support for the Company's commercial paper program. As of December 31, 2016, $78 million was used for letters of credit and $522 million remained unused. The Facility does not contain a material adverse change clause at the time of borrowing. Subject to applicable market conditions, the Company expects to renew or replace the Facility, as needed, prior to expiration. In connection therewith, the Company may extend the maturity date and/or increase or decrease the lending commitment thereunder. The Company's subsidiaries are not parties to the Facility.

The Company is required to pay a commitment fee on the unused balance of the Facility. This fee is less than 1/4 of 1%. The Facility contains a covenant that limits the ratio of debt to capitalization (each as defined in the Facility) to a maximum of 65%. For purposes of this definition, debt excludes any project debt incurred by certain subsidiaries of the Company to the extent such debt is non-recourse to the Company, and capitalization excludes the capital stock or other equity attributable to such subsidiary. At December 31, 2017, the Company was in compliance with its debt limits.

The Company also has a $120 million continuing letter of credit facility expiring in 2019 for standby letters of credit. At December 31, 2017, $101 million has been used for letters of credit, primarily as credit support for PPA requirements, and $19 million remains unused. At December 31, 2016, the total amount available under this facility was $82 million. The Company's subsidiaries are not parties to this letter of credit facility.

In addition, at both December 31, 2017 and 2016, the Company has $113 million of cash collateral posted related to PPA requirements, which is included in other deferred charges and assets in the consolidated balance sheets.

Commercial Paper Program

The Company's commercial paper program is used to finance acquisition and construction costs related to electric generating facilities and for general corporate purposes. The Company's subsidiaries are not parties to the commercial paper program. Commercial paper is included in notes payable in the consolidated balance sheets as noted below:

Commercial
Paper at the
End of the
Period

| | Amount Outstanding | Weighted Average Interest Rate |
|---|---|---|
| | (in millions) | |
| December 31, 2017 | $105 | 2.0 % |
| December 31, 2016 | $— | N/A |

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Subsidiary Project Credit Facilities

In connection with the construction of solar facilities by RE Tranquillity LLC, RE Garland Holdings LLC, and RE Roserock LLC, indirect subsidiaries of the Company, each subsidiary had entered into separate credit agreements (Project Credit Facilities), which were non-recourse to the Company (other than the subsidiary party to the agreement). Each Project Credit Facility provided (a) a senior secured construction loan credit facility, (b) a senior secured bridge loan facility, and (c) a senior secured letter of credit facility that was secured by the membership interests of the respective project company, with proceeds directed to finance project costs related to the respective solar facilities. Each Project Credit Facility was secured by the assets of the applicable project subsidiary and membership interests of the applicable project subsidiary. The Tranquillity and Garland Project Credit Facilities were fully repaid on October 14, 2016 and December 29, 2016, respectively. The table below summarizes the Roserock Project Credit Facility as of December 31, 2016, which was extended to January 31, 2017 and fully repaid on January 17, 2017.

| | Construction Loan Facility | Bridge Loan Facility | Total Loan Facility | Loan Facility Undrawn | Letter of Credit Facility | Letter of Credit Facility Undrawn |
|---|---|---|---|---|---|---|
| | (in millions) | | | | | |
| December 31, 2016 | $63 | $ 180 | $ 243 | $ 34 | $ 23 | $ 16 |

The Project Credit Facilities had no amount outstanding at December 31, 2017 and $209 million outstanding with a weighted average interest rate of 2.1% as of December 31, 2016.

Assets Subject to Lien

Under the terms of the PPA and the expansion PPA for the Mankato project, approximately $442 million of assets, primarily related to property, plant, and equipment, are subject to lien at December 31, 2017. See Note 11 for additional information.

Roserock is in a litigation dispute with 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. See Note 3 for additional information.

Dividend Restrictions

The Company can only pay dividends to Southern Company out of retained earnings or paid-in-capital.

7. COMMITMENTS

Fuel Agreements

SCS, as agent for the Company and the traditional electric operating companies, has entered into various fuel transportation and procurement agreements to supply a portion of the fuel (primarily natural gas) requirements for the Company's generating facilities. These purchase obligations are not recognized on the Company's consolidated balance sheets. The Company incurred fuel expense of $621 million, $456 million, and $441 million for the years ended December 31, 2017, 2016, and 2015, respectively, the majority of which was purchased under long-term commitments. The Company expects that a substantial amount of its future fuel needs will continue to be purchased under long-term commitments.

SCS may enter into various types of wholesale energy and natural gas contracts acting as an agent for the Company and Southern Company's traditional electric operating companies. Under these agreements, each of the traditional electric operating companies and the Company may be jointly and severally liable. Southern Company has entered into keep-well agreements with each of the traditional electric operating companies to ensure they will not subsidize or be responsible for any costs, losses, liabilities, or damages resulting from the inclusion of the Company as a contracting party under these agreements.

Operating Leases

The Company has operating lease agreements with various terms and expiration dates. Total rent expense was $29 million, $22 million, and $7 million for the years ended December 31, 2017, 2016, and 2015, respectively. These amounts include contingent rent expense related to land leases based on wind production and escalation in the Consumer Price Index for All Urban Consumers. The Company excludes contingent rent but includes step rents, fixed escalations, lease concessions, and lease extensions in its computation of minimum lease payments, which are recognized on a straight-line basis over the minimum lease term. As of December 31, 2017, estimated minimum lease payments under operating leases were $22 million in each of 2018, 2019, and 2020, $23 million in each of 2021 and 2022, and $815 million in 2023 and thereafter. The majority of the committed future expenditures are related to land leases for solar and wind facilities.

NOTES (continued)
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Redeemable Noncontrolling Interests
See Note 10.
8. 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) | Total |
| | (in millions) | | | |
| Assets: | | | | |
| Energy-related derivatives | $— | $ 3 | $ — | $3 |
| Foreign currency derivatives | — | 129 | — | 129 |
| Cash equivalents | 21 | — | — | 21 |
| Total | $21 | $ 132 | $ — | $153 |
| Liabilities: | | | | |
| Energy-related derivatives | $— | $ 13 | $ — | $13 |
| Foreign currency derivatives | — | 23 | — | 23 |
| Contingent consideration | — | — | 22 | 22 |
| Total | $— | $ 36 | $ 22 | $58 |

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As of December 31, 2016, assets and liabilities measured at fair value on a recurring basis during the period, together with their associated level of the fair value hierarchy, were as follows:

| | Fair Value Measurements Using | | | |
|---|---|---|---|---|
| As of December 31, 2016: | Quoted Prices in Active Markets for Identical Assets (Level 1) | Significant Other Observable Inputs (Level 2) | Significant Unobservable Inputs (Level 3) | Total |
| | (in millions) | | | |
| Assets: | | | | |
| Energy-related derivatives | $— | $ 21 | $ — | $21 |
| Interest rate derivatives | — | 1 | — | 1 |
| Cash equivalents | 628 | — | — | 628 |
| Total | $628 | $ 22 | $ — | $650 |
| Liabilities: | | | | |
| Energy-related derivatives | $— | $ 5 | $ — | $5 |
| Foreign currency derivatives | — | 58 | — | 58 |
| Contingent consideration | — | — | 18 | 18 |
| Total | $— | $ 63 | $ 18 | $81 |

Valuation Methodologies

The energy-related derivatives primarily consist of over-the-counter financial products for natural gas and physical power products, including, from time to time, basis swaps. These are standard products used within the energy industry and are valued using the market approach. The inputs used are mainly from observable market sources, such as forward natural gas prices, power prices, implied volatility, and overnight index swap interest rates. Interest rate derivatives are also standard over-the-counter products that are valued using observable market data and assumptions commonly used by market participants. The fair value of interest rate derivatives reflects the net present value of expected payments and receipts under the swap agreement based on the market's expectation of future interest rates. Additional inputs to the net present value calculation may include the contract terms, counterparty credit risk, and occasionally, implied volatility of interest rate options. The 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 9 for additional information on how these derivatives are used.

The Company has contingent payment obligations related to certain acquisitions whereby the Company 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.

NOTES (continued)
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As of December 31, 2017 and 2016, other financial instruments for which the carrying amount did not equal fair value were as follows:

| | Carrying Amount | Fair Value |
|---|---|---|
| | (in millions) | |
| Long-term debt, including securities due within one year: | | |
| 2017 | $5,841 | $6,079 |
| 2016 | $5,628 | $5,691 |

The fair values are determined using Level 2 measurements and are based on quoted market prices for the same or similar issues or on the current rates available to the Company.

## 9. DERIVATIVES

The Company is exposed to market risks, primarily commodity price risk and interest rate risk, and occasionally foreign currency exchange rate risk. To manage the volatility attributable to these exposures, the Company nets its exposures, where possible, to take advantage of natural offsets and enters into various derivative transactions for the remaining exposures pursuant to the Company's policies in areas such as counterparty exposure and risk management practices. The Company's policy is that derivatives are to be used primarily for hedging purposes and mandates strict adherence to all applicable risk management policies. Derivative positions are monitored using techniques including, but not limited to, market valuation, value at risk, stress testing, and sensitivity analysis. Derivative instruments are recognized at fair value in the consolidated balance sheets as either assets or liabilities and are presented on a net basis. See Note 8 for additional fair value 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

The Company enters into energy-related derivatives to hedge exposures to electricity, natural gas, and other fuel price changes. The Company has limited exposure to market volatility in energy-related commodity prices because its long-term sales contracts shift substantially all fuel cost responsibility to the purchaser. However, the Company has been and may continue to be exposed to market volatility in energy-related commodity prices as a result of uncontracted generating capacity.

Energy-related derivative contracts are accounted for under one of two methods:

- Cash Flow Hedges – Gains and losses on energy-related derivatives designated as cash flow hedges which are used to hedge anticipated purchases and sales and are initially deferred in OCI before being recognized in the consolidated 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 consolidated statements of income as incurred.

Some energy-related derivative contracts require physical delivery as opposed to financial settlement, and this type of derivative is both common and prevalent within the electric industry. When an energy-related derivative contract is settled physically, any cumulative unrealized gain or loss is reversed and the contract price is recognized in the respective line item representing the actual price of the underlying goods being delivered.

At December 31, 2017, the net volume of energy-related derivative contracts for natural gas positions totaled 14 million mmBtu, all of which expire in 2018. At December 31, 2017, the net volume of energy-related derivative contracts for power positions was 3 million MWHs, all of which expire in 2018.

In addition to the volume discussed above, the Company enters into physical natural gas supply contracts that provide the option to sell back excess natural gas due to operational constraints. The maximum expected volume of natural gas subject to such a feature is 10 million mmBtu.

For cash flow hedges, gains (losses) expected to be reclassified from accumulated OCI to earnings for the 12-month period ending December 31, 2018 is $(7) million.

NOTES (continued)
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Interest Rate Derivatives

The Company may also enter into interest rate derivatives to hedge exposure to changes in interest rates. Derivatives related to existing variable rate securities or forecasted transactions are accounted for as cash flow hedges where the effective portion of the derivatives' fair value gains or losses is recorded in OCI and is reclassified into earnings at the same time the hedged transactions affect earnings. The derivatives employed as hedging instruments are structured to minimize ineffectiveness, which is recorded directly to earnings. Fair value gains or losses on derivatives that are not designated or fail to qualify as hedges are recognized in the consolidated statements of income as incurred. At December 31, 2017, the Company did not have any interest rate derivatives outstanding and does not have any deferred gains and losses in AOCI related to cash flow hedges that would be reclassified from AOCI to interest expense.

Foreign Currency Derivatives

The Company 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

The Company enters into energy-related and interest rate derivative contracts that may contain provisions that permit intra-contract netting of derivative receivables and payables for routine billing and offsets related to events of default and settlements. Fair value amounts of derivative assets and liabilities on the consolidated balance sheets are presented net to the extent that there are netting arrangements or similar agreements with counterparties.

At December 31, 2017 and 2016, the fair value of energy-related, interest rate, and foreign currency derivatives reflected in the consolidated balance sheets is as follows:

NOTES (continued)
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| Derivative Category and Balance Sheet Location | 2017 Assets | 2017 Liabilities | 2016 Assets | 2016 Liabilities |
|---|---|---|---|---|
| | (in millions) | | | |
| Derivatives designated as hedging instruments in cash flow and fair value hedges | | | | |
| Energy-related derivatives: | | | | |
| Other current assets/Other current liabilities | $3 | $ 11 | $18 | $ 4 |
| 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 | $132 | $ 34 | $18 | $ 62 |
| Derivatives not designated as hedging instruments | | | | |
| Energy-related derivatives: | | | | |
| Other current assets/Other current liabilities | $— | $ 2 | $3 | $ 1 |
| Interest rate derivatives: | | | | |
| Other current assets/Other current liabilities | — | — | 1 | — |
| Total derivatives not designated as hedging instruments | $— | $ 2 | $4 | $ 1 |
| Gross amounts of recognized assets and liabilities | $132 | $ 36 | $22 | $ 63 |
| Gross amounts offset | $(3) | $ (3) | $(5) | $ (5) |
| Net amounts of assets and liabilities | $129 | $ 33 | $17 | $ 58 |

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For the years ended December 31, 2017, 2016, and 2015, the pre-tax effects of energy-related, interest rate, and foreign currency derivatives designated as cash flow hedging instruments on the consolidated statements of income were as follows:

| Derivatives in Cash Flow Hedging Relationships | Gain (Loss) Recognized in OCI on Derivative (Effective Portion) | | | Gain (Loss) Reclassified from AOCI into Income (Effective Portion) | | | |
|---|---|---|---|---|---|---|---|
| Derivative Category | 2017 | 2016 | 2015 | Statements of Income Location | 2017 | 2016 | 2015 |
| | (in millions) | | | | (in millions) | | |
| Energy-related derivatives | $(38) | $14 | $ — | Amortization | $(17) | $2 | $— |
| Interest rate derivatives | — | — | — | Interest expense, net of amounts capitalized | — | (1) | (1) |
| Foreign currency derivatives | 140 | (58) | — | Interest expense, net of amounts capitalized | (23) | (13) | — |
| | | | | Other income (expense), net | 159 | (82) | — |
| Total | $102 | $(44) | $ — | | $119 | $(94) | $(1) |

There was no material ineffectiveness recorded in earnings for any period presented.
The pre-tax effects of energy-related derivatives and interest rate derivatives not designated as hedging instruments on the Company's consolidated statements of income were not material for any year presented.

Contingent Features

The Company does not have any credit arrangements that would require material changes in payment schedules or terminations as a result of a credit rating downgrade. There are certain derivatives that could require collateral, but not accelerated payment, in the event of various credit rating changes of certain affiliated companies. At December 31, 2017, there was no collateral posted with the Company's derivative counterparties.

At December 31, 2017, the fair value of derivative liabilities with contingent features was $8 million. However, the fair value of derivative liabilities with contingent features, including certain agreements that could require collateral in the event that one or more Southern Company system power pool participants has a credit rating change to below investment grade because of joint and several liability features underlying these derivatives, was $12 million at December 31, 2017.

Generally, collateral may be provided by a Southern Company guaranty, letter of credit, or cash. If collateral is required, fair value amounts recognized for the right to reclaim cash collateral or the obligation to return cash collateral are not offset against fair value amounts recognized for derivatives executed with the same counterparty.

The Company maintains accounts with certain regional transmission organizations to facilitate financial derivative transactions. Based on the value of the positions in these accounts and the associated margin requirements, the Company may be required to post collateral. At December 31, 2017, cash collateral posted was immaterial.

The Company is exposed to losses related to financial instruments in the event of counterparties' nonperformance. The Company only enters into agreements and material transactions with counterparties that have investment grade credit ratings by Moody's and S&P or with counterparties who have posted collateral to cover potential credit exposure. The Company has also established risk management policies and controls to determine and monitor the creditworthiness of counterparties in order to mitigate the Company's exposure to counterparty credit risk. Therefore, the Company does not anticipate a material adverse effect on the financial statements as a result of counterparty nonperformance.

10. NONCONTROLLING INTERESTS

In April 2017, approximately $114 million was reclassified from redeemable noncontrolling interests to non-redeemable noncontrolling interests due to the expiration of an option allowing SunPower Corporation to require the Company to purchase its redeemable noncontrolling interest at fair market value. In addition, Turner Renewable Energy, LLC owned a 10% redeemable noncontrolling interest in certain of the Company's solar facilities. These noncontrolling interests were redeemed in October 2017 at fair market value pursuant to the partnership agreement. As of December 31, 2017, there were no outstanding redeemable noncontrolling interests.

NOTES (continued)
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The following table presents the changes in redeemable noncontrolling interests for the years ended December 31:

| | 2017 | 2016 | 2015 |
|---|---|---|---|
| | (in millions) | | |
| Beginning balance | $164 | $ 43 | $ 39 |
| Net income attributable to redeemable noncontrolling interests | 2 | 4 | 2 |
| Distributions to redeemable noncontrolling interests | (2) | (1) | — |
| Capital contributions from redeemable noncontrolling interests | 2 | 118 | 2 |
| Redemption of redeemable noncontrolling interests | (59) | — | — |
| Reclassification to non-redeemable noncontrolling interests | (114) | — | — |
| Change in fair value of redeemable noncontrolling interests | 7 | — | — |
| Ending balance | $— | $ 164 | $ 43 |

The following table presents the attribution of net income to the Company and the noncontrolling interests for the years ended December 31:

| | 2017 | 2016 | 2015 |
|---|---|---|---|
| | (in millions) | | |
| Net income | $1,117 | $374 | $229 |
| Less: Net income attributable to noncontrolling interests | 44 | 32 | 12 |
| Less: Net income attributable to redeemable noncontrolling interests | 2 | 4 | 2 |
| Net income attributable to the Company | $1,071 | $338 | $215 |

11. ACQUISITIONS

During 2017 and 2016, in accordance with its overall growth strategy, the Company or one of its wholly-owned subsidiaries, acquired or contracted to acquire the projects discussed below. Also, in March 2016, the Company acquired an additional 15% interest in Desert Stateline, 51% of which was initially acquired in 2015. As a result, the Company and the class B member are now entitled to 66% and 34%, respectively, of all cash distributions from Desert Stateline. In addition, the Company 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 the Company's acquisition activity for the year ended, and subsequent to, December 31, 2017.

| Project Facility | Resource | Seller, Acquisition Date | Approximate Nameplate Capacity (MW) | Location | Ownership Percentage | 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 |
| Asset Acquisitions Subsequent to December 31, 2017 | | | | | | | |
| Gaskell West 1 | Solar | Recurrent Energy Development Holdings, LLC, January 26, 2018 | 20 | Kern County, CA | 100% of Class B[(b)] | March 2018 | 20 years |

(a) On July 31, 2017, the Company purchased 100% of the Cactus Flats facility and commenced construction. Upon placing the facility in service, the Company 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) The Company owns 100% of the class B membership interest under a tax equity partnership agreement.

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Business Acquisitions During the Year Ended December 31, 2017
The Company'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:

| | 2017 (in millions) |
|---|---|
| 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 in the consolidated statements of income by the Company 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, the Company 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 the Company's renewable development strategy, the Company 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, the Company 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, the Company 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.

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The following table presents the Company'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 Corporation, 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 Corporation, 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 Wind Global LLC, October 26, 2016 | 257 | Floyd and Crosby Counties, TX | 90.1 | % (f) | October 2016 | 12 years |

(a) The Company owns 100% of the class A membership interests and a wholly-owned subsidiary of the seller owns 100% of the class B membership interests. The Company and the class B member are entitled to 51% and 49%, respectively, of all cash distributions from the project. In addition, the Company is entitled to substantially all of the federal tax benefits with respect to the transaction.

(b) The Company originally purchased 90%, with a minority owner owning 10%. During 2017, the Company acquired the remaining 10% ownership interest. See Note 10 for additional information.

(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) The Company owns 90.1%, with the minority owner, Invenergy Wind Global LLC, owning 9.9%.

NOTES (continued)
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Acquisitions During the Year Ended December 31, 2016
The Company'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 the Company was approximately $2.6 billion for these acquisitions. In connection with the Company'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:

| | 2016 (in millions) |
|---|---|
| CWIP | $ 2,354 |
| Property, plant, and equipment | 302 |
| Intangible assets [a] | 128 |
| Other assets | 52 |
| Accounts payable | (16 ) |
| Debt | (217 ) |
| Total purchase price | $ 2,603 |
| | |
| Funded by: | |
| The Company [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 consolidated 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 consolidated 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.

NOTES (continued)
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12. QUARTERLY FINANCIAL INFORMATION (UNAUDITED)
Summarized quarterly financial information for 2017 and 2016 is as follows:

| Quarter Ended | Operating Revenues | Operating Income | Income Tax (Benefit) | Net Income Attributable to the Company |
|---|---|---|---|---|
| | (in millions) | | | |
| March 2017 | $450 | $ 65 | $ (52) | $ 70 |
| June 2017 | 529 | 112 | (38) | 82 |
| September 2017 | 618 | 159 | (39) | 124 |
| December 2017 (*) | 478 | 32 | (810) | 795 |
| | | | | |
| March 2016 | $315 | $ 47 | $ (23) | $ 50 |
| June 2016 | 373 | 81 | (41) | 89 |
| September 2016 | 500 | 134 | (102) | 176 |
| December 2016 | 389 | 28 | (29) | 23 |

(*) As a result of the Tax Reform Legislation, the Company recorded an income tax benefit of $743 million in the fourth quarter 2017. See Note 5 for additional information.

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

SELECTED CONSOLIDATED FINANCIAL AND OPERATING DATA 2013-2017
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| | 2017 | 2016 | 2015 | 2014 | 2013 |
|---|---|---|---|---|---|
| Operating Revenues (in millions): | | | | | |
| Wholesale — non-affiliates | $1,671 | $1,146 | $964 | $1,116 | $923 |
| Wholesale — affiliates | 392 | 419 | 417 | 383 | 346 |
| Total revenues from sales of electricity | 2,063 | 1,565 | 1,381 | 1,499 | 1,269 |
| Other revenues | 12 | 12 | 9 | 2 | 6 |
| Total | $2,075 | $1,577 | $1,390 | $1,501 | $1,275 |
| Net Income Attributable to Southern Power (in millions)[(a)] | $1,071 | $338 | $215 | $172 | $166 |
| Cash Dividends on Common Stock (in millions) | $317 | $272 | $131 | $131 | $129 |
| Return on Average Common Equity (percent)[(a)] | 22.39 | 9.79 | 10.16 | 10.39 | 10.73 |
| Total Assets (in millions)[(b)(c)] | $15,206 | $15,169 | $8,905 | $5,233 | $4,417 |
| Property, Plant, and Equipment — In Service (in millions) | $13,755 | $12,728 | $7,275 | $5,657 | $4,696 |
| Capitalization (in millions): | | | | | |
| Common stock equity | $5,138 | $4,430 | $2,483 | $1,752 | $1,564 |
| Redeemable noncontrolling interests | — | 164 | 43 | 39 | 29 |
| Noncontrolling interests | 1,360 | 1,245 | 781 | 219 | — |
| Long-term debt[(b)] | 5,071 | 5,068 | 2,719 | 1,085 | 1,607 |
| Total (excluding amounts due within one year) | $11,569 | $10,907 | $6,026 | $3,095 | $3,200 |
| Capitalization Ratios (percent): | | | | | |
| Common stock equity | 44.4 | 40.6 | 41.2 | 56.6 | 48.9 |
| Redeemable noncontrolling interests | — | 1.5 | 0.7 | 1.3 | 0.9 |
| Noncontrolling interests | 11.8 | 11.4 | 13.0 | 7.1 | — |
| Long-term debt[(b)] | 43.8 | 46.5 | 45.1 | 35.0 | 50.2 |
| Total (excluding amounts due within one year) | 100.0 | 100.0 | 100.0 | 100.0 | 100.0 |
| Kilowatt-Hour Sales (in millions): | | | | | |
| Wholesale — non-affiliates | 35,920 | 23,213 | 18,544 | 19,014 | 15,111 |
| Wholesale — affiliates | 12,811 | 15,950 | 16,567 | 11,194 | 9,359 |
| Total | 48,731 | 39,163 | 35,111 | 30,208 | 24,470 |
| Plant Nameplate Capacity Ratings (year-end) (megawatts) | 12,940 | 12,442 | 9,808 | 9,185 | 8,924 |
| Maximum Peak-Hour Demand (megawatts): | | | | | |
| Winter | 3,421 | 3,469 | 3,923 | 3,999 | 2,685 |
| Summer | 4,224 | 4,303 | 4,249 | 3,998 | 3,271 |
| Annual Load Factor (percent) | 49.1 | 50.0 | 49.0 | 51.8 | 54.2 |
| Plant Availability (percent) | 99.9 | 91.6 | 93.1 | 91.8 | 91.8 |
| Source of Energy Supply (percent): | | | | | |
| Natural gas | 67.7 | 79.4 | 89.5 | 86.0 | 88.5 |
| Solar, Wind, and Biomass | 22.8 | 12.1 | 4.3 | 2.9 | 1.1 |
| Purchased power — | | | | | |
| From non-affiliates | 7.8 | 6.8 | 4.7 | 6.4 | 6.4 |
| From affiliates | 1.7 | 1.7 | 1.5 | 4.7 | 4.0 |
| Total | 100.0 | 100.0 | 100.0 | 100.0 | 100.0 |
| Employees (year-end)[(d)] | 541 | — | — | — | — |

(a) As a result of the Tax Reform Legislation, the Company recorded an income tax benefit of $743 million in 2017.

(b) A reclassification of debt issuance costs from Total Assets to Long-term debt of $11 million and $12 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 $306 million and $- million is reflected for years 2014 and 2013, respectively, in accordance with new accounting standards adopted in 2015 and applied retrospectively.

(d) Prior to the employee transfer in December 2017, the Company had no employees, but was billed employee related costs from SCS.

SOUTHERN COMPANY GAS
FINANCIAL SECTION

## MANAGEMENT'S REPORT ON INTERNAL CONTROL OVER FINANCIAL REPORTING

Southern Company Gas and Subsidiary Companies 2017 Annual Report

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

Under management's supervision, an evaluation of the design and effectiveness of the Company's internal control over financial reporting was conducted based on the framework in Internal Control—Integrated Framework (2013) issued by the Committee of Sponsoring Organizations of the Treadway Commission. Based on this evaluation, management concluded that the Company's internal control over financial reporting was effective as of December 31, 2017.

/s/ Andrew W. Evans
Andrew W. Evans
Chairman, President, and Chief Executive Officer

/s/ Elizabeth W. Reese
Elizabeth W. Reese
Executive Vice President, Chief Financial Officer, and Treasurer
February 20, 2018

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the stockholder and the Board of Directors of Southern Company Gas and Subsidiary Companies

Opinion on the Financial Statements

We have audited the accompanying consolidated balance sheets and consolidated statements of capitalization of Southern Company Gas and Subsidiary Companies (the Company) (a wholly-owned subsidiary of The Southern Company) as of December 31, 2017 and 2016, the related consolidated statements of income, comprehensive income, stockholders' equity, and cash flows for the year ended December 31, 2017 and the six month periods ended June 30, 2016 (Predecessor) and December 31, 2016 (Successor), and the related notes (collectively referred to as the "financial statements"). In our opinion, the financial statements (pages II-593 to II-651) 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 the year ended December 31, 2017 and the six months ended June 30, 2016 (Predecessor) and December 31, 2016 (Successor), in conformity with accounting principles generally accepted in the United States of America.

Basis for Opinion

These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on the Company's financial statements based on our audits. We did not audit the financial statements of Southern Natural Gas Company, L.L.C. (SNG), the Company's investment in which is accounted for by the use of the equity method. The accompanying consolidated financial statements of the Company include its equity investment in SNG of $1,262 million and $1,394 million as of December 31, 2017 and December 31, 2016, respectively, and its earnings from its equity method investment in SNG of $88 million and $56 million for the year ended December 31, 2017 and the six months ended December 31, 2016, respectively. Those statements were audited by other auditors whose report (which expresses an unqualified opinion on SNG's financial statements and contains an emphasis of matter paragraph concerning the extent of its operations and relationships with affiliated entities) have been furnished to us, and our opinion, insofar as it relates to the amounts included for SNG, is based solely on the report of the other auditors. 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 audit to obtain reasonable assurance about whether the financial statements are free of material misstatement, whether due to error or fraud. The Company is not required to have, nor were we engaged to perform, an audit of its internal control over financial reporting. As part of our audits, we are required to obtain an understanding of internal control over financial reporting but not for the purpose of expressing an opinion on the effectiveness of the Company's internal control over financial reporting. Accordingly, we express no such opinion.

Our audits included performing procedures to assess the risks of material misstatement of the financial statements, whether due to error or fraud, and performing procedures that 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. We believe that our audits and the report of the other auditors provide a reasonable basis for our opinion.

/s/ Deloitte & Touche LLP

Atlanta, Georgia

February 20, 2018

We have served as the Company's auditor since 2016.

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the stockholder and the Board of Directors of Southern Company Gas and Subsidiary Companies

In our opinion, the consolidated statement of income, comprehensive income, common stockholders' equity, and cash flows present fairly, in all material respects, the results of operations and cash flows of Southern Company Gas (formerly AGL Resources Inc.) and its subsidiaries for the year ended December 31, 2015, in conformity with accounting principles generally accepted in the United States of America. In addition, in our opinion, the financial statement schedule for the year ended December 31, 2015 presents fairly, in all material respects, the information set forth therein when read in conjunction with the related consolidated financial statements. These financial statements and financial statement schedule are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements and the financial statement schedule based on our audit. We conducted our audit of these financial statements in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, and evaluating the overall financial statement presentation. We believe that our audit provides a reasonable basis for our opinion.

/s/ PricewaterhouseCoopers LLP
Atlanta, Georgia
February 11, 2016

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DEFINITIONS

| Term | Meaning |
|---|---|
| AFUDC | Allowance for funds used during construction |
| 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 |
| Chattanooga Gas | Chattanooga Gas Company |
| Chicago Hub | A venture of Nicor Gas, which provides natural gas storage and transmission-related services to marketers and gas distribution companies |
| CUB | Citizens Utility Board, in Illinois |
| Dalton Pipeline | A 50% undivided ownership interest in a pipeline facility in Georgia |
| EBIT | Earnings before interest and taxes |
| EPA | U.S. Environmental Protection Agency |
| FASB | Financial Accounting Standards Board |
| FERC | Federal Energy Regulatory Commission |
| Fitch | Fitch Ratings, Inc. |
| GAAP | U.S. generally accepted accounting principles |
| Heating Degree Days | A measure of weather, calculated when the average daily temperatures are less than 65 degrees Fahrenheit |
| Heating Season | The period from November through March when natural gas usage and operating revenues are generally higher |
| Horizon Pipeline | Horizon Pipeline Company, LLC |
| Illinois Commission | Illinois Commerce Commission |
| IRS | Internal Revenue Service |
| ITC | Investment tax credit |
| LIBOR | London Interbank Offered Rate |
| LIFO | Last-in, first-out |
| LNG | Liquefied natural gas |
| LOCOM | Lower of weighted average cost or current market price |
| Marketers | Marketers selling retail natural gas in Georgia and certificated by the Georgia PSC |
| Merger | The merger of a wholly-owned, direct subsidiary of Southern Company, with and into Southern Company Gas, effective July 1, 2016, with Southern Company Gas continuing as the surviving corporation and a wholly-owned, direct subsidiary of Southern Company |
| MGP | Manufactured gas plant |
| mmBtu | Million British thermal units |
| Moody's | Moody's Investors Service, Inc. |
| natural gas distribution utilities | Southern Company Gas' seven natural gas distribution utilities (Nicor Gas, Atlanta Gas Light, Virginia Natural Gas, Elizabethtown Gas, Florida City Gas, Chattanooga Gas, and Elkton Gas) |
| New Jersey BPU | New Jersey Board of Public Utilities |
| Nicor Gas | Northern Illinois Gas Company, doing business as Nicor Gas Company |
| NYMEX | New York Mercantile Exchange, Inc. |
| OCI | Other comprehensive income |

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DEFINITIONS
(continued)

| Term | Meaning |
|---|---|
| PennEast Pipeline | PennEast Pipeline Company, LLC |
| Piedmont | Piedmont Natural Gas Company, Inc. |
| Pivotal Utility Holdings | Pivotal Utility Holdings, Inc., a wholly-owned subsidiary of Southern Company Gas, doing business as Elizabethtown Gas, Elkton Gas, and Florida City Gas |
| PRP | Pipeline Replacement Program, Atlanta Gas Light's 15-year infrastructure replacement program, which ended in December 2013 |
| PSC | Public Service Commission |
| 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 |
| Sequent | Sequent Energy Management, L.P. |
| SNG | Southern Natural Gas Company, L.L.C. |
| Southern Company | The Southern Company |
| Southern Company Gas Capital | Southern Company Gas Capital Corporation, a 100%-owned subsidiary of Southern Company Gas |
| Southern Company system | Southern Company, the traditional electric operating companies, Southern Power, Southern Company Gas (as of July 1, 2016), Southern Electric Generating Company, Southern Nuclear, SCS, Southern Linc, PowerSecure, Inc. (as of May 9, 2016), and other subsidiaries |
| Southern Holdings | Southern Company Holdings, Inc. |
| Southern Linc | Southern Communications Services, Inc. |
| Southern Nuclear | Southern Nuclear Operating Company, Inc. |
| Southern Power | Southern Power Company and its subsidiaries |
| SouthStar | SouthStar Energy Services, LLC |
| STRIDE | Atlanta Gas Light's Strategic Infrastructure Development and Enhancement program |
| traditional electric operating companies | Alabama Power Company, Georgia Power Company, Gulf Power Company, and Mississippi Power Company |
| 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 |
| Triton | Triton Container Investments, LLC |
| VIE | Variable interest entity |
| Virginia Commission | Virginia State Corporation Commission |
| Virginia Natural Gas | Virginia Natural Gas, Inc. |
| WACOG | Weighted average cost of gas |

MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS
Southern Company Gas and Subsidiary Companies 2017 Annual Report
OVERVIEW
Business Activities
Southern Company Gas is an energy services holding company whose primary business is the distribution of natural gas through utilities in seven states – Illinois, Georgia, Virginia, New Jersey, Florida, Tennessee, and Maryland. Southern Company Gas and its subsidiaries (the Company) are also involved in several other complementary businesses.
The Company has four reportable segments – gas distribution operations, gas marketing services, wholesale gas services, and gas midstream operations – and one non-reportable segment, all other. See Note 12 to the financial statements for additional information.
Many factors affect the opportunities, challenges, and risks of the Company's business. These factors include the ability to maintain safety, to maintain constructive regulatory environments, to maintain and grow natural gas sales and number of customers, and to effectively manage and secure timely recovery of costs. These costs include those related to projected long-term demand growth, environmental standards, reliability, natural gas, and capital expenditures, including updating and expanding the natural gas distribution systems. The 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 Company for the foreseeable future.
Merger, Acquisition, and Disposition Activities
On July 1, 2016, the Company completed the Merger, pursuant to which the Company became a wholly-owned subsidiary of Southern Company. Southern Company accounted for the Merger using the acquisition method of accounting whereby the assets acquired and liabilities assumed were recognized at fair value as of the acquisition date. Pushdown accounting was applied to create a new cost basis for the Company's assets, liabilities, and equity as of the acquisition date. Accordingly, the successor financial statements reflect the new basis of accounting, and successor and predecessor period financial results (separated by a heavy black line) are presented, but are not comparable. As a result of the application of acquisition accounting, certain discussions herein include disclosure of the predecessor and successor periods. See Note 11 to the financial statements under "Merger with Southern Company" for additional information.
In September 2016, the Company paid approximately $1.4 billion to acquire a 50% equity interest in SNG, which is the owner of a 7,000-mile pipeline system connecting natural gas supply basins in Texas, Louisiana, Mississippi, and Alabama to markets in Louisiana, Mississippi, Alabama, Florida, Georgia, South Carolina, and Tennessee. The investment in SNG is accounted for using the equity method. On March 31, 2017, the Company made an additional $50 million contribution to maintain its 50% equity interest in SNG. See Note 4 to the financial statements under "Equity Method Investments – SNG" and Note 11 to the financial statements under "Investment in SNG" for additional information.
In October 2016, the Company completed its purchase of Piedmont's 15% interest in SouthStar for $160 million. See Note 4 to the financial statements under "Variable Interest Entities" for additional information.
On October 15, 2017, the Company's 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. 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, the Company 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. The Company 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.

Operating Metrics

The Company continues to focus on several operating metrics, including Heating Degree Days, customer count, and volumes of natural gas sold.

MANAGEMENT'S DISCUSSION AND ANALYSIS (continued)
Southern Company Gas and Subsidiary Companies 2017 Annual Report

The Company measures weather and the effect on its business using Heating Degree Days. Generally, increased Heating Degree Days result in higher demand for natural gas on the Company's distribution system. With the exception of the Company's utilities in Illinois and Florida, the Company has various regulatory mechanisms, such as weather normalization and straight-fixed-variable rate design, which limit its exposure to weather changes within typical ranges in each of its utilities' respective service territory. However, the utility customers in Illinois and the gas marketing services customers primarily in Georgia, Illinois, and Ohio can be impacted by warmer- or colder-than-normal weather. The Company utilizes weather hedges to reduce negative earnings impact in the event of warmer-than-normal weather, while retaining most of the earnings upside for these businesses.

The number of customers served by gas distribution operations and gas marketing services can be impacted by natural gas prices, economic conditions, and competition from alternative fuels. Gas marketing services' customers are primarily located in Georgia, Illinois, and Ohio.

The Company's natural gas volume metrics for gas distribution operations and gas marketing services illustrate the effects of weather and customer demand for natural gas. Wholesale gas services' physical sales volumes represent the daily average natural gas volumes sold to its customers.

See RESULTS OF OPERATIONS herein for additional information on these operating metrics.

Seasonality of Results

During the Heating Season, natural gas usage and operating revenues are generally higher as more customers are connected to the gas distribution systems and natural gas usage is higher in periods of colder weather. Occasionally in the summer, wholesale gas services' operating revenues are impacted due to peak usage by power generators in response to summer energy demands. The Company's base operating expenses, excluding cost of natural gas, bad debt expense, and certain incentive compensation costs, are incurred relatively evenly throughout the year. Seasonality also affects the comparison of certain balance sheet items across quarters, including receivables, unbilled revenues, natural gas for sale, and notes payable. However, these items are comparable when reviewing the Company's annual results.

Thus, the Company's operating results can vary significantly from quarter to quarter as a result of seasonality, which is illustrated in the table below.

| | Percent Generated During Heating Season | | |
|---|---|---|---|
| | Operating Revenues | EBIT | Net Income |
| Successor - 2017 | 67.3% | 69.6 % | 73.7 % |
| Successor - July 1, 2016 through December 31, 2016 | 67.1% | 81.5 % | 96.5 % |
| Predecessor - January 1, 2016 through June 30, 2016 | 70.0% | 107.0% | 138.9% |
| Predecessor - 2015 | 68.1% | 77.3 % | 85.0 % |

Earnings

Net income attributable to the Company for the successor year ended December 31, 2017 was $243 million, which included net income of $53 million from the Company's investment in SNG (including $18 million related to a non-cash charge recorded by SNG to establish a regulatory liability associated with the Tax Reform Legislation) and $44 million generated from the Company's continued investment in infrastructure replacement programs and base rate increases at Atlanta Gas Light, Elizabethtown Gas, and Virginia Natural Gas, less the associated increases in depreciation. Net income also reflects $130 million of additional tax expense resulting from the revaluation of deferred tax assets of $93 million related to the Tax Reform Legislation and $37 million associated with State of Illinois income tax legislation enacted in the third quarter 2017 and new income tax apportionment factors in several states resulting from the Company's inclusion in the consolidated Southern Company state tax filings. Also included in net income was $17 million of additional expense resulting from the pushdown of acquisition accounting. See FUTURE EARNINGS POTENTIAL – "Income Tax Matters" herein and Notes 5 and 11 to the financial statements for

additional information.
Net income attributable to the Company for the successor period of July 1, 2016 through December 31, 2016 was $114 million, which included $26 million in earnings from the SNG investment, net of related interest expense, partially offset by $12 million of additional expense resulting from the impact of the pushdown of acquisition accounting and $27 million of Merger-related expenses.
Net income attributable to the Company for the predecessor periods of January 1, 2016 through June 30, 2016 and the year ended December 31, 2015 were $131 million and $353 million, respectively, which included $41 million and $26 million, respectively, of Merger-related expenses, and $14 million and $20 million, respectively, of net income attributable to the SouthStar

MANAGEMENT'S DISCUSSION AND ANALYSIS (continued)
Southern Company Gas and Subsidiary Companies 2017 Annual Report

noncontrolling interest, which the Company purchased in October 2016. Net income for the predecessor periods reflected higher revenues from continued investment in infrastructure programs, partially offset by warm weather, net of hedging, and low earnings from wholesale gas services due to mark-to-market losses.

RESULTS OF OPERATIONS

Operating Results

A condensed income statement for the Company follows:

| | Successor | | Predecessor | |
|---|---|---|---|---|
| | Year Ended December 31, | July 1, 2016 through December 31, | January 1, 2016 through June 30, | Year Ended December 31, |
| | 2017 | 2016 | 2016 | 2015 |
| | (in millions) | | (in millions) | |
| Operating revenues | $3,920 | $ 1,652 | $1,905 | $ 3,941 |
| Cost of natural gas and other sales | 1,630 | 623 | 769 | 1,645 |
| Other operations and maintenance | 940 | 482 | 454 | 928 |
| Depreciation and amortization | 501 | 238 | 206 | 397 |
| Taxes other than income taxes | 184 | 71 | 99 | 181 |
| Merger-related expenses | — | 41 | 56 | 44 |
| Total operating expenses | 3,255 | 1,455 | 1,584 | 3,195 |
| Operating income | 665 | 197 | 321 | 746 |
| Earnings from equity method investments | 106 | 60 | 2 | 6 |
| Interest expense, net of amounts capitalized | 200 | 81 | 96 | 175 |
| Other income (expense), net | 39 | 14 | 5 | 9 |
| Earnings before income taxes | 610 | 190 | 232 | 586 |
| Income taxes | 367 | 76 | 87 | 213 |
| Net Income | 243 | 114 | 145 | 373 |
| Less: Net income attributable to noncontrolling interest | — | — | 14 | 20 |
| Net Income Attributable to Southern Company Gas | $243 | $ 114 | $131 | $ 353 |

Operating Revenues

Operating revenues for the successor year ended December 31, 2017 and the successor period of July 1, 2016 through December 31, 2016 were $3.9 billion and $1.7 billion, respectively. For the predecessor periods of January 1, 2016 through June 30, 2016 and the year ended December 31, 2015, operating revenues were $1.9 billion and $3.9 billion, respectively.

For the successor year ended December 31, 2017, natural gas revenues included recovery of $1.6 billion in cost of natural gas and $6 million in net revenues from wholesale gas services, net of $21 million of amortization associated with assets established in the application of acquisition accounting. Also included in natural gas revenues for the successor year ended December 31, 2017 were $99 million in additional revenues generated from gas distribution operations as a result of continued investment in infrastructure replacement programs and increases in base rate revenues at Atlanta Gas Light, Elizabethtown Gas, and Virginia Natural Gas. Natural gas revenues were partially offset by a $13 million negative impact of warmer-than-normal weather, net of hedging.

For the successor period of July 1, 2016 through December 31, 2016, natural gas revenues included recovery of $613 million in cost of natural gas and $24 million in net revenues from wholesale gas services, net of $5 million of amortization associated with assets established in the application of acquisition accounting. Natural gas revenues were partially offset by a $5 million decrease attributable to warmer-than-normal weather, net of hedging.

For the predecessor periods of January 1, 2016 through June 30, 2016 and the year ended December 31, 2015, natural gas revenues included recovery of $755 million and $1.6 billion, respectively, in cost of natural gas, as well as $32 million in net losses and $202 million in net revenues, respectively, from wholesale gas services. For the predecessor period of January 1, 2016 through June 30, 2016, natural gas revenues included a negative impact of $7 million attributable to warmer-than-normal weather,

MANAGEMENT'S DISCUSSION AND ANALYSIS (continued)
Southern Company Gas and Subsidiary Companies 2017 Annual Report

net of hedging. For the predecessor year ended December 31, 2015, natural gas revenues included a positive impact of $2 million also attributable to warmer-than-normal weather, net of hedging.

See "Segment Information" herein for additional information on wholesale gas services' revenues and losses.

Natural gas distribution rates include provisions to adjust billings for fluctuations in natural gas costs. Therefore, gas costs recovered through natural gas revenues generally equal the amount expensed in cost of natural gas and do not affect net income from gas distribution operations. See "Cost of Natural Gas" herein for additional information.

Revenue impacts from weather and customer growth are described further below.

During Heating Season, natural gas usage and operating revenues are generally higher. Weather typically does not have a significant net income impact during the non-Heating Season. The following table presents the Heating Degree Days information for Illinois and Georgia, the primary locations where the Company's operations are impacted by weather.

| | Years Ended December 31, | | | | 2017 vs. normal | 2017 vs. 2016 | 2016 vs. 2015 |
|---|---|---|---|---|---|---|---|
| | Normal[(a)] | 2017 | 2016 | 2015 | (warmer) | colder (warmer) | (warmer) |
| | (in thousands) | | | | | | |
| Illinois[(b)] | 5,869 | 5,246 | 5,243 | 5,433 | (10.6 )% | 0.1 % | (3.5 )% |
| Georgia | 2,614 | 1,970 | 2,175 | 2,204 | (24.6 )% | (9.4 )% | (1.3 )% |

(a) Normal represents the 10-year average from January 1, 2007 through December 31, 2016 for Illinois at Chicago Midway International Airport and for Georgia at Atlanta Hartsfield-Jackson International Airport, based on information obtained from the National Oceanic and Atmospheric Administration, National Climatic Data Center.

(b) The 10-year average Heating Degree Days established by the Illinois Commission in Nicor Gas' 2009 rate case is 5,600 annually from 1998 through 2007.

The Company hedged its exposure to warmer-than-normal weather at Nicor Gas in Illinois; therefore, the weather-related negative pre-tax income impact on gas distribution operations was limited to $4 million ($2 million after tax), $1 million ($1 million after tax), $7 million ($5 million after tax), and a positive impact of $2 million ($1 million after tax) for the successor year ended December 31, 2017, the successor period of July 1, 2016 through December 31, 2016, the predecessor period of January 1, 2016 through June 30, 2016, and the predecessor year ended December 31, 2015, respectively.

The Company also hedged its exposure to warmer-than-normal weather at gas marketing services in Georgia and Illinois; therefore, the weather-related negative pre-tax income impact on gas marketing services was limited to $9 million ($5 million after tax) and $4 million ($3 million after tax) for the successor year ended December 31, 2017 and the successor period of July 1, 2016 through December 31, 2016, respectively. There was no weather impact for the predecessor period of January 1, 2016 through June 30, 2016 or the predecessor year ended December 31, 2015.

The following table provides the number of customers served by the Company for the periods presented:

| | December 31, | | |
|---|---|---|---|
| | 2017[(a)] | 2016[(a)] | 2015[(b)] |
| | (in thousands, except market share %) | | |
| Gas distribution operations | 4,623 | 4,586 | 4,526 |
| Gas marketing services | | | |
| Energy customers[(c)] | 774 | 656 | 645 |
| Market share of energy customers in Georgia | 29.2 % | 29.6 % | 29.7 % |
| Service contracts | 1,184 | 1,198 | 1,171 |

(a) Includes customer and contract counts at December 31, 2017 and 2016.

(b) Includes average customer and contract counts for the year ended December 31, 2015.

(c) Includes approximately 140,000 customers at December 31, 2017 that were contracted to serve beginning April 1, 2017.

The Company anticipates overall customer growth trends at gas distribution operations to continue as it expects continued improvement in the new housing market and low natural gas prices. The Company uses a variety of targeted marketing programs to attract new customers and to retain existing customers.

Gas marketing services' market share in Georgia decreased at December 31, 2017 compared to the two prior years as a result of a highly competitive marketing environment, which is expected to continue for the foreseeable future. The Company will continue efforts at gas marketing services to enter into targeted markets and expand its energy customers and service contracts.

MANAGEMENT'S DISCUSSION AND ANALYSIS (continued)
Southern Company Gas and Subsidiary Companies 2017 Annual Report

Cost of Natural Gas and Other Sales

Natural gas costs are the largest expense for the Company. Excluding Atlanta Gas Light, which does not sell natural gas to end-use customers, gas distribution operations 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. Gas distribution operations defers or accrues the difference between the actual cost of natural gas and the amount of commodity revenue earned in a given period. The deferred or accrued amount is either billed or refunded to customers prospectively through adjustments to the commodity rate. Deferred natural gas costs are reflected as regulatory assets and accrued natural gas costs are reflected as regulatory liabilities. Therefore, gas costs recovered through natural gas revenues generally equal the amount expensed in cost of natural gas and do not affect net income from gas distribution operations. Cost of natural gas at gas distribution operations represented 79.6% of total cost of natural gas for 2017. Gas marketing services customers are charged for actual or estimated natural gas consumed. Cost of natural gas includes the cost of fuel, lost and unaccounted for gas, adjustments to reduce the value of inventories to market value, and gains and losses associated with certain derivatives.

Cost of natural gas was $1.6 billion for the successor year ended December 31, 2017, which reflected an increase in natural gas pricing of 26.3% during the year compared to 2016, partially offset by lower demand for natural gas.

For the successor period of July 1, 2016 through December 31, 2016, cost of natural gas was $613 million and reflected low demand for natural gas driven by warm weather in the fourth quarter 2016.

Cost of natural gas was $755 million and $1.6 billion for the predecessor period of January 1, 2016 through June 30, 2016 and the year ended December 31, 2015, respectively, and reflected low demand for natural gas driven by warm weather during those periods.

The following table details the volumes of natural gas sold during all periods presented.

| | Year Ended December 31, | | | 2017 vs. 2016 | 2016 vs. 2015 |
|---|---|---|---|---|---|
| | 2017 | 2016 | 2015 | % Change | % Change |
| Gas distribution operations (mmBtu in millions) | | | | | |
| Firm | 667 | 670 | 695 | (0.4 )% | (3.6 )% |
| Interruptible | 95 | 96 | 99 | (1.0 )% | (3.0 )% |
| Total | 762 | 766 | 794 | (0.5 )% | (3.5 )% |
| Gas marketing services (mmBtu in millions) | | | | | |
| Firm: | | | | | |
| Georgia | 23 | 34 | 35 | (32.4)% | (2.9 )% |
| Illinois | 8 | 12 | 13 | (33.3)% | (7.7 )% |
| Other emerging markets | 15 | 12 | 11 | 25.0 % | 9.1 % |
| Interruptible large commercial and industrial | 11 | 14 | 14 | (21.4)% | — % |
| Total | 57 | 72 | 73 | (20.8)% | (1.4 )% |
| Wholesale gas services | | | | | |
| Daily physical sales (mmBtu in millions/day) | 6.4 | 7.4 | 6.8 | (13.5)% | 8.8 % |

Other Operations and Maintenance Expenses

For the successor year ended December 31, 2017, other operations and maintenance expenses were $940 million and primarily reflected compensation and benefit costs and professional services, including pipeline compliance and maintenance and legal services.

For the successor period of July 1, 2016 through December 31, 2016, other operations and maintenance expenses were $482 million and primarily reflected compensation and benefit costs and professional services, including pipeline compliance and maintenance and legal services.

For the predecessor period of January 1, 2016 through June 30, 2016, other operations and maintenance expenses were $454 million consistent with the level of expenses in the corresponding period in 2015.

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For the predecessor year ended December 31, 2015, other operations and maintenance expenses were $928 million and included pipeline compliance and maintenance costs, compensation and benefit costs, and a $14 million goodwill impairment charge. See ACCOUNTING POLICIES – "Assessment of Assets" herein and Note 1 to the financial statements under "Goodwill and Other Intangible Assets and Liabilities" for additional information on the goodwill impairment charge.

Depreciation and Amortization

For the successor year ended December 31, 2017, depreciation and amortization was $501 million and included $38 million of additional amortization of intangible assets as a result of fair value adjustments in acquisition accounting, primarily at gas marketing services and $28 million in additional depreciation at gas distribution operations, primarily due to continued investment in infrastructure programs.

For the successor period of July 1, 2016 through December 31, 2016, depreciation and amortization was $238 million and included $23 million of additional amortization of intangible assets as a result of fair value adjustments in acquisition accounting, primarily at gas marketing services, as well as depreciation at gas distribution operations due to continued investment in infrastructure programs.

For the predecessor periods of January 1, 2016 through June 30, 2016 and the year ended December 31, 2015, depreciation and amortization was $206 million and $397 million, respectively, and reflected depreciation related to additional assets placed in service at gas distribution operations due to continued investment in infrastructure programs.

See Notes 3 and 11 to the financial statements under "Regulatory Matters – Regulatory Infrastructure Programs" and "Merger with Southern Company," respectively, for additional information on infrastructure programs and the application of acquisition accounting.

Taxes Other Than Income Taxes

For the successor year ended December 31, 2017, taxes other than income taxes were $184 million, which consisted primarily of revenue tax expenses, property taxes, and payroll taxes.

For the successor period of July 1, 2016 through December 31, 2016, taxes other than income taxes were $71 million, which consisted primarily of revenue tax expenses, property taxes, and payroll taxes.

For the predecessor periods of January 1, 2016 through June 30, 2016 and the year ended December 31, 2015, taxes other than income taxes were $99 million and $181 million, respectively, which consisted primarily of revenue tax expenses, property taxes, and payroll taxes.

Merger-Related Expenses

There were no Merger-related expenses in the successor year ended December 31, 2017.

For the successor period of July 1, 2016 through December 31, 2016, Merger-related expenses were $41 million, including $18 million in rate credits provided to the customers of Elizabethtown Gas and Elkton Gas as conditions of the Merger, $20 million for additional compensation-related expenses, and $3 million for financial advisory fees, legal expenses, and other Merger-related costs.

For the predecessor periods of January 1, 2016 through June 30, 2016 and the year ended December 31, 2015, Merger-related expenses were $56 million and $44 million, respectively, including $31 million and $20 million, respectively, for financial advisory fees, legal expenses, and other Merger-related costs, and $25 million and $24 million, respectively, for additional compensation-related expenses.

See Note 11 to the financial statements under "Merger with Southern Company" for additional information.

Earnings from Equity Method Investments

For the successor year ended December 31, 2017, earnings from equity method investments were $106 million, reflecting $88 million in earnings from the Company's investment in SNG, including $33 million related to a non-cash charge recorded by SNG to establish a regulatory liability associated with the Tax Reform Legislation, and $18 million in earnings from all other investments.

For the successor period of July 1, 2016 through December 31, 2016, earnings from equity method investments were $60 million, reflecting $56 million in earnings from the Company's investment in SNG and $4 million in earnings from all other investments.
For the predecessor periods of January 1, 2016 through June 30, 2016 and the year ended December 31, 2015, earnings from equity method investments were not material.

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See Notes 4 and 11 to the financial statements under "Equity Method Investments" and "Investment in SNG," respectively, for additional information on the Company's investment in SNG.

Interest Expense, Net of Amounts Capitalized

For the successor year ended December 31, 2017, interest expense, net of amounts capitalized was $200 million, which includes the $38 million fair value adjustment on long-term debt in acquisition accounting. Interest expense also reflects debt issuances and redemptions during the period and the recognition of previously deferred interest related to regulatory infrastructure programs.

For the successor period of July 1, 2016 through December 31, 2016, interest expense, net of amounts capitalized was $81 million, which includes the $19 million fair value adjustment on long-term debt in acquisition accounting. Interest expense also reflects debt issuances and redemptions during the period and the recognition of previously deferred interest related to regulatory infrastructure programs.

For the predecessor periods of January 1, 2016 through June 30, 2016 and the year ended December 31, 2015, interest expense, net of amounts capitalized was $96 million and $175 million, respectively, reflecting debt issuances and redemptions during the period and the recognition of previously deferred interest related to regulatory infrastructure programs.

See FUTURE EARNINGS POTENTIAL – "Unrecognized Ratemaking Amounts" herein for additional information on the unrecognized costs related to the infrastructure programs. Also see FINANCIAL CONDITION AND LIQUIDITY – "Financing Activities" herein and Note 6 to the financial statements for additional information on outstanding debt.

Other Income (Expense), Net

For the successor year ended December 31, 2017, other income (expense), net was $39 million and primarily related to a $20 million gain from the settlement of contractor litigation claims, tax gross-up on contributions in aid of construction, and AFUDC. See Note 3 to the financial statements under "Regulatory Matters – PRP Settlement" for additional information on contractor litigation claims.

For the successor period of July 1, 2016 through December 31, 2016, other income (expense), net was $14 million and primarily related to the tax gross-up of contributions in aid of construction received from customers.

For the predecessor periods of January 1, 2016 through June 30, 2016 and the year ended December 31, 2015, other income (expense), net was not material.

Income Taxes

For the successor year ended December 31, 2017, income taxes were $367 million. The effective tax rate in 2017 reflects additional expense from the revaluation of deferred tax assets of $93 million associated with the Tax Reform Legislation and $37 million associated with State of Illinois income tax legislation enacted in the third quarter 2017 and new income tax apportionment factors in several states resulting from the Company's inclusion in the consolidated Southern Company state tax filings.

For the successor period of July 1, 2016 through December 31, 2016, income taxes were $76 million. The effective tax rate during this period reflects certain nondeductible Merger-related charges.

For the predecessor periods of January 1, 2016 through June 30, 2016 and the year ended December 31, 2015, income taxes were $87 million and $213 million, respectively. The effective tax rate in both periods reflects certain nondeductible Merger-related expenses and other charges.

The effective tax rate for each period presented is consistent when adjusted for the additional expense recorded from the revaluation of deferred tax assets associated with the Tax Reform Legislation, the State of Illinois income tax legislation enacted in the third quarter 2017, the allocation of new income tax apportionment factors in several states resulting from the Company's inclusion in the consolidated Southern Company state tax filings in 2017, and the nondeductible Merger-related charges for each period in 2017, 2016, and 2015.

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

Noncontrolling Interest

Prior to the October 2016 acquisition of Piedmont's 15% interest in SouthStar, net income attributable to noncontrolling interest was recorded on the statements of income and totaled $14 million and $20 million in the predecessor periods of January 1, 2016 through June 30, 2016 and the year ended December 31, 2015, respectively. See Note 4 to the financial statements under

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"Variable Interest Entities" for additional information.

Effects of Inflation

The Company is subject to rate regulation that is generally based on the recovery of historical and projected costs. The effects of inflation can create an economic loss since the recovery of costs could be in dollars that have less purchasing power. Any adverse effect of inflation on the Company's results of operations has not been substantial in recent years.

Performance and Non-GAAP Measures

Prior to the Merger, the Company evaluated segment performance using EBIT, which includes operating income, earnings from equity method investments, and other income (expense), net. EBIT excludes interest expense, net of amounts capitalized and income taxes (benefit), which were evaluated on a consolidated basis for those periods. EBIT is used herein to discuss the results of the Company's segments for the predecessor periods, as EBIT was the primary measure of segment profit or loss for those periods. Subsequent to the Merger, the Company changed its segment performance measure from EBIT to net income to better align with the performance measure utilized by Southern Company. EBIT for the year ended December 31, 2017 and the period of July 1, 2016 through December 31, 2016 presented herein is considered a non-GAAP measure. The Company also discusses consolidated EBIT, which is considered a non-GAAP measure for all periods presented. The presentation of consolidated EBIT is believed to provide useful supplemental information regarding a consolidated measure of profit or loss. The Company further believes the presentation of segment EBIT for the year ended December 31, 2017 and the period of July 1, 2016 through December 31, 2016 is useful as it allows for a measure of comparability to other companies with different capital and legal structures, which accordingly may be subject to different interest rates and effective tax rates. The applicable reconciliations of net income to consolidated EBIT and segment EBIT are provided herein.

Adjusted operating margin is a non-GAAP measure that is calculated as operating revenues less cost of natural gas, cost of other sales, and revenue tax expense. Adjusted operating margin excludes other operations and maintenance expenses, depreciation and amortization, taxes other than income taxes, and Merger-related expenses, which are included in the calculation of operating income as calculated in accordance with GAAP and reflected in the statements of income. The presentation of adjusted operating margin is believed to provide useful information regarding the contribution resulting from customer growth at gas distribution operations since the cost of natural gas and revenue tax expense can vary significantly and are generally billed directly to customers. The Company further believes that utilizing adjusted operating margin at gas marketing services, wholesale gas services, and gas midstream operations allows it to focus on a direct measure of performance before overhead costs. The applicable reconciliation of operating income to adjusted operating margin is provided herein.

EBIT and adjusted operating margin should not be considered alternatives to, or more meaningful indicators of, the Company's operating performance than net income attributable to the Company or operating income as determined in accordance with GAAP. In addition, the Company's adjusted operating margin may not be comparable to similarly titled measures of other companies.

See RESULTS OF OPERATIONS herein for information on the Company's financial performance.

Reconciliations of operating income to adjusted operating margin and net income attributable to Southern Company Gas to EBIT are as follows:

| | Successor | | Predecessor | |
|---|---|---|---|---|
| | Year Ended December 31, 2017 | July 1, 2016 through December 31, 2016 | January 1, 2016 through June 30, 2016 | Year Ended December 31, 2015 |

| | | | | |
|---|---|---|---|---|
| | (in millions) | | (in millions) | |
| Operating Income | $665 | $ 197 | $321 | $ 746 |
| Other operating expenses[a] | 1,625 | 832 | 815 | 1,550 |
| Revenue tax expense[b] | (98 ) | (31 ) | (56 ) | (101 ) |
| Adjusted Operating Margin | $2,192 | $ 998 | $1,080 | $ 2,195 |

(a) Includes other operations and maintenance, depreciation and amortization, taxes other than income taxes, and Merger-related expenses.
(b) Nicor Gas' revenue tax expenses, which are passed through directly to customers.

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| | Successor | | Predecessor | |
|---|---|---|---|---|
| | Year Ended December 31, | July 1, 2016 through December 31, | January 1, 2016 through June 30, | Year Ended December 31, |
| | 2017 | 2016 | 2016 | 2015 |
| | (in millions) | | (in millions) | |
| Net Income Attributable to Southern Company Gas | $243 | $ 114 | $131 | $ 353 |
| Net income attributable to noncontrolling interest | — | — | 14 | 20 |
| Income taxes | 367 | 76 | 87 | 213 |
| Interest expense, net of amounts capitalized | 200 | 81 | 96 | 175 |
| EBIT | $810 | $ 271 | $328 | $ 761 |

Segment Information

Adjusted operating margin, operating expenses, and the Company's primary performance metric for each segment are illustrated in the tables below.

| | Successor | | | | | |
|---|---|---|---|---|---|---|
| | Year ended December 31, 2017 | | | July 1, 2016 through December 31, 2016 | | |
| | Adjusted Operating Margin(*) | Operating Expenses(*) | Net Income | Adjusted Operating Margin(*) | Operating Expenses(*) | Net Income |
| | (in millions) | | | (in millions) | | |
| Gas distribution operations | $1,834 | $ 1,184 | $ 353 | $817 | $ 595 | $ 77 |
| Gas marketing services | 313 | 200 | 84 | 139 | 112 | 19 |
| Wholesale gas services | 5 | 56 | (57) | 24 | 26 | — |
| Gas midstream operations | 42 | 52 | 3 | 19 | 26 | 20 |
| All other | 10 | 47 | (140) | 3 | 46 | (2) |
| Intercompany eliminations | (12) | (12) | — | (4) | (4) | — |
| Consolidated | $2,192 | $ 1,527 | $ 243 | $998 | $ 801 | $ 114 |

(*) Adjusted operating margin and operating expenses are adjusted for Nicor Gas revenue tax expenses, which are passed through directly to customers.

| | Predecessor | | | | | |
|---|---|---|---|---|---|---|
| | January 1, 2016 through June 30, 2016 | | | Year ended December 31, 2015 | | |
| | Adjusted Operating Margin(*) | Operating Expenses(*) | EBIT | Adjusted Operating Margin(*) | Operating Expenses(*) | EBIT |
| | (in millions) | | | (in millions) | | |
| Gas distribution operations | $911 | $ 560 | $353 | $1,657 | $ 1,086 | $581 |
| Gas marketing services | 190 | 81 | 109 | 317 | 165 | 152 |
| Wholesale gas services | (36) | 33 | (68) | 183 | 71 | 110 |
| Gas midstream operations | 15 | 24 | (6) | 36 | 62 | (23) |
| All other | 4 | 65 | (60) | 7 | 70 | (59) |

| | | | | | | |
|---|---|---|---|---|---|---|
| Intercompany eliminations | (4 ) | (4 ) | — | (5 ) | (5 ) | — |
| Consolidated | $1,080 | $ 759 | $328 | $2,195 | $ 1,449 | $761 |

(*) Adjusted operating margin and operating expenses are adjusted for Nicor Gas revenue tax expenses, which are passed through directly to customers.

Gas Distribution Operations

Gas distribution operations is the largest component of the Company's business and is subject to regulation and oversight by agencies in each of the states it serves. These agencies approve natural gas rates designed to provide the Company with the opportunity to generate revenues to recover the cost of natural gas delivered to its customers and its fixed and variable costs, including depreciation, interest, maintenance, taxes, and overhead costs, and to earn a reasonable return on its investments.

With the exception of Atlanta Gas Light, the Company's second largest utility that operates in a deregulated natural gas market and has a straight-fixed-variable rate design that minimizes the variability of its revenues based on consumption, the earnings of the natural gas distribution utilities can be affected by customer consumption patterns that are a function of weather conditions, price levels for natural gas, and general economic conditions that may impact customers' ability to pay for natural gas consumed. The Company has various weather mechanisms, such as weather normalization mechanisms and weather derivative instruments, that limit its exposure to weather changes within typical ranges in its natural gas distribution utilities' service territories.

Successor Year Ended December 31, 2017

Net income of $353 million includes $1.8 billion in adjusted operating margin, $1.2 billion in operating expenses, and $34 million in other income (expense), net, which resulted in EBIT of $684 million. Net income also includes $153 million in interest expense, net of amounts capitalized and $178 million in income tax expense. Adjusted operating margin reflects $99 million in additional revenue from continued investment in infrastructure replacement programs and base rate increases at Atlanta Gas Light, Elizabethtown Gas, and Virginia Natural Gas. Adjusted operating margin was also affected by increased customer growth, partially offset by the negative impact of warmer-than-normal weather, net of hedging. Operating expenses reflect a $28 million increase in depreciation associated with additional assets placed in service, as well as benefit and compensation costs, legal expenses, and pipeline compliance and maintenance expenses. Other income (expense), net reflects a $20 million gain from the settlement of contractor litigation claims. Interest expense reflects the impact of intercompany promissory notes executed in December 2016 and the issuance of first mortgage bonds at Nicor Gas on August 10, 2017 and November 1, 2017. Income tax expense includes a $22 million benefit as a result of the Tax Reform Legislation.

See Note 3 to the financial statements under "Regulatory Matters – PRP Settlement" for additional information on contractor litigation claims. See FINANCIAL CONDITION AND LIQUIDITY – "Financing Activities" herein and Note 6 to the financial statements for additional information on debt issuances. See FUTURE EARNINGS POTENTIAL – "Income Tax Matters" herein and Note 5 to the financial statements for additional information.

Successor Period of July 1, 2016 through December 31, 2016

Net income of $77 million includes $817 million in adjusted operating margin, $595 million in operating expenses, and $11 million in other income (expense), net, resulting in EBIT of $233 million. Net income also includes $105 million in interest expense, net of amounts capitalized and $51 million in income tax expense. Adjusted operating margin reflects revenue from continued investment in infrastructure replacement programs, partially offset by the impact of warm weather, net of hedging. Operating expenses reflect the depreciation associated with additional assets placed in service, the related expenses associated with pipeline compliance and maintenance activities, and $18 million of rate credits provided to the customers of Elizabethtown Gas and Elkton Gas as conditions of the Merger. See Note 11 to the financial statements under "Merger with Southern Company" for additional information.

Predecessor Period of January 1, 2016 through June 30, 2016

EBIT of $353 million includes $911 million in adjusted operating margin, $560 million in operating expense, and $2 million in other income (expense), net. Adjusted operating margin reflects increased revenue from continued investment in infrastructure replacement programs and the impact of customer usage and growth, partially offset by the impact of warm weather, net of hedging. Operating expenses reflect the depreciation associated with additional assets placed in service.

Predecessor Year Ended December 31, 2015

EBIT of $581 million includes $1.7 billion in adjusted operating margin, $1.1 billion in operating expense, and $10 million in other income (expense), net. Adjusted operating margin reflects revenue from the continued investment in infrastructure replacement programs, the impact of customer usage and growth, and the impact of warm weather, net of hedging. Operating expenses reflect the depreciation associated with additional assets placed in service, as well as benefits and compensation costs.

Gas Marketing Services

Gas marketing services consists of several businesses that provide energy-related products and services to natural gas markets, including warranty sales. Gas marketing services is weather sensitive and uses a variety of hedging strategies, such as weather derivative instruments and other risk management tools, to partially mitigate potential weather impacts. Operating expenses primarily reflect employee costs, marketing, customer care, and bad debt expenses.

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Successor Year Ended December 31, 2017

Net income of $84 million includes $313 million in adjusted operating margin and $200 million in operating expenses, which resulted in EBIT of $113 million. Net income also includes $5 million in interest expense, net of amounts capitalized and $24 million in income tax expense. Adjusted operating margin reflects a $9 million negative impact of warmer-than-normal weather, net of hedging, and $4 million in unrealized hedge losses, net of recoveries. Operating expenses includes $40 million in additional amortization of intangible assets established in the application of acquisition accounting. Income tax expense includes a $19 million benefit as a result of the Tax Reform Legislation. See FUTURE EARNINGS POTENTIAL – "Income Tax Matters" herein and Note 5 to the financial statements for additional information.

Successor Period of July 1, 2016 through December 31, 2016

Net income of $19 million includes $139 million in adjusted operating margin and $112 million in operating expenses, resulting in EBIT of $27 million. Net income also includes $1 million in interest expense, net of amounts capitalized and $7 million in income tax expense. Adjusted operating margin reflects a reduction of $5 million due to fair value adjustments to certain assets and liabilities in the application of acquisition accounting. Also reflected in adjusted operating margin are unrealized hedge gains and LOCOM adjustments. Operating expenses reflect $23 million in additional amortization of intangible assets, partially offset by a $2 million reduction in operations and maintenance expense due to fair value adjustments to certain assets and liabilities in the application of acquisition accounting. See Note 1 to the financial statements under "Natural Gas for Sale" for additional information on LOCOM adjustments and Note 11 to the financial statements for additional information on the Merger.

Predecessor Period of January 1, 2016 through June 30, 2016

EBIT of $109 million includes $190 million in adjusted operating margin and $81 million in operating expenses. Adjusted operating margin reflects $9 million in unrealized hedge gains. Operating expenses reflect lower bad debt, marketing, and depreciation and amortization, compared to the same period in the prior year. Earnings also include $14 million attributable to noncontrolling interest.

Predecessor Year Ended December 31, 2015

EBIT of $152 million includes $317 million in adjusted operating margin and $165 million in operating expenses. Adjusted operating margin reflects revenue from gas marketing and warranty sales, which were partially offset by the impact of warm weather, net of hedging. Operating expenses primarily reflect compensation and benefits costs. Earnings also include $20 million attributable to noncontrolling interest.

Wholesale Gas Services

Wholesale gas services is involved in asset management and optimization, storage, transportation, producer and peaking services, natural gas supply, natural gas services, and wholesale gas marketing. The Company has positioned the business to generate positive economic earnings on an annual basis even under low volatility market conditions that can result from a number of factors. When market price volatility increases, wholesale gas services is well positioned to capture significant value and generate stronger results. Wholesale gas services generated positive economic results for the successor year ended December 31, 2017, primarily reflecting lower volatility market conditions throughout the majority of 2017 and higher volatility along with the widening of locational and transportation spreads in December 2017 due to colder weather, as well as higher natural gas storage value resulting from higher natural gas prices.

Successor Year Ended December 31, 2017

Net loss of $57 million includes $5 million in adjusted operating margin, $56 million in operating expenses, and $1 million in other income (expense), net, which resulted in a loss before interest and taxes of $50 million. Also included are $7 million in interest expense, net of amounts capitalized. Adjusted operating margin reflects a decrease of $21 million due to fair value adjustments to certain assets and liabilities in the application of acquisition accounting. Also reflected in adjusted operating margin is revenue from commercial activity partially offset by mark-to-market losses.

Income tax expense includes $21 million resulting from the revaluation of deferred income tax assets associated with the Tax Reform Legislation. See FUTURE EARNINGS POTENTIAL – "Income Tax Matters" herein and Note 5 to the financial statements for additional information on income taxes.

Successor Period of July 1, 2016 through December 31, 2016

Net income includes $24 million in adjusted operating margin, $26 million in operating expenses, and $2 million in other income (expense), net, resulting in no EBIT. Also included are $3 million in interest expense, net of amounts capitalized and $3 million in income tax benefit. Adjusted operating margin reflects a decrease of $5 million due to fair value adjustments to certain assets and liabilities in the application of acquisition accounting. Also reflected in adjusted operating margin are mark-to-market gains due to changes in natural gas prices in the fourth quarter 2016 and losses from commercial activity due to low volatility in natural gas prices and warm weather. Operating expenses reflect low incentive compensation expense due to low earnings.

Predecessor Period of January 1, 2016 through June 30, 2016

Loss before interest and taxes of $68 million includes $(36) million in adjusted operating margin, $33 million in operating expense, and $1 million in other income (expense), net. Adjusted operating margin reflects mark-to-market losses and LOCOM adjustments as a result of changes in natural gas prices and revenues from commercial activity driven by changes in price volatility. Operating expenses reflect lower incentive compensation expense as compared to the same period in the prior year due to lower earnings.

Predecessor Year Ended December 31, 2015

EBIT of $110 million includes $183 million in adjusted operating margin, $71 million in operating expenses, and $(2) million in other income (expense), net. Adjusted operating margin reflects revenue from commercial activity driven by changes in price volatility, mark-to-market gains, and LOCOM adjustments as a result of changes in natural gas prices.

The following table illustrates the components of wholesale gas services' adjusted operating margin for the periods presented:

| | Successor | | Predecessor | |
|---|---|---|---|---|
| | Year Ended December 31, 2017 | July 1, 2016 through December 31, 2016 | January 1, 2016 through June 30, 2016 | Year Ended December 31, 2015 |
| | (in millions) | | (in millions) | |
| Commercial activity recognized | $116 | $ (15 ) | $34 | $ 140 |
| Gain (loss) on storage derivatives | 23 | (20 ) | (38 ) | 45 |
| Gain (loss) on transportation and forward commodity derivatives | (113 ) | 64 | (31 ) | 11 |
| LOCOM adjustments, net of current period recoveries | — | — | (1 ) | (13 ) |
| Purchase accounting adjustments to fair value inventory and contracts | (21 ) | (5 ) | — | — |
| Adjusted operating margin | $5 | $ 24 | $(36) | $ 183 |

Change in Commercial Activity

The commercial activity at wholesale gas services includes recognition of storage and transportation values that were generated in prior periods, which reflect the impact of prior period hedge gains and losses as associated physical transactions occur. Warmer-than-normal weather during the 2016/2017 Heating Season, lower power generation volumes, and build-out of new U.S. pipeline infrastructure, along with increases in natural gas supply, caused low volatility and a tightening of locational or transportation spreads throughout the majority of 2017, negatively impacting the amount of commercial activity revenues generated relative to demand fees for contracted pipeline transportation and storage capacity, and minimum sharing under asset management agreements. However, during December 2017, significantly colder weather increased natural gas price volatility and transportation spreads widened, enabling wholesale gas services to capture higher commercial activity. Further, as natural gas prices and forward storage or time spreads increased, wholesale gas services was able to capture higher storage values that it expects to recognize as commercial activity revenues when natural gas is physically withdrawn from storage.

Change in Storage and Transportation Derivatives

Volatility in the natural gas market arises from a number of factors, such as weather fluctuations or changes in supply or demand for natural gas in different regions of the U.S. The volatility of natural gas commodity prices has a significant impact on the Company's customer rates, long-term competitive position against other energy sources, and the ability of wholesale gas services to capture value from locational and seasonal spreads. Transportation and forward commodity derivative losses are primarily the result of widening transportation spreads during the fourth quarter 2017 due to significantly colder weather in the Northeast and Midwest U.S., which impacted forward prices at natural gas receipt and delivery points. Additionally, during 2017, forward storage or time spreads applicable to the locations of wholesale gas services' specific storage positions resulted in storage derivative gains.

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The natural gas that the Company purchases and injects into storage is accounted for at the LOCOM value utilizing gas daily or spot prices at the end of the year. Wholesale gas services recorded LOCOM adjustments of $19 million for the predecessor year ended December 31, 2015. LOCOM adjustments for all other periods presented were immaterial. See Note 1 to the financial statements under "Natural Gas for Sale" for additional information.

Withdrawal Schedule and Physical Transportation Transactions

The expected natural gas withdrawals from storage and expected offset to prior hedge losses/gains associated with the transportation portfolio of wholesale gas services are presented in the following table, along with the net operating revenues expected at the time of withdrawal from storage and the physical flow of natural gas between contracted transportation receipt and delivery points. Wholesale gas services' expected net operating revenues exclude storage and transportation demand charges, as well as other variable fuel, withdrawal, receipt, and delivery charges, but are net of the estimated impact of profit sharing under its asset management agreements. Further, the amounts that are realizable in future periods are based on the inventory withdrawal schedule, planned physical flow of natural gas between the transportation receipt and delivery points, and forward natural gas prices at December 31, 2017. A portion of wholesale gas services' storage inventory and transportation capacity is economically hedged with futures contracts, which results in the realization of substantially fixed net operating revenues.

| | Storage Withdrawal | | Physical Transportation Transactions – Expected Net Operating Gains(b) |
|---|---|---|---|
| | Total storage (WACOG $2.66) | Expected net operating gains(a) | |
| | (in mmBtu in millions) | (in millions) | (in millions) |
| 2018 | 55.2 | $ 14 | $ 70 |
| 2019 and thereafter | 2.3 | 1 | 43 |
| Total at December 31, 2017 | 57.5 | $ 15 | $ 113 |

(a) Represents expected operating gains from planned storage withdrawals associated with existing inventory positions and could change as wholesale gas services adjusts its daily injection and withdrawal plans in response to changes in future market conditions and forward NYMEX price fluctuations. Also includes the impact of purchase accounting adjustments to reflect natural gas storage inventory at market value. Excluding the impact of these adjustments, the expected net operating gains at December 31, 2017 would have been $22 million.

(b) Represents the periods associated with the transportation derivative (gains) and losses during which the derivatives will be settled and the physical transportation transactions will occur that offset the derivative losses that were previously recognized.

Gas Midstream Operations

Gas midstream operations consists primarily of gas pipeline investments, with storage and fuels also aggregated into this segment. Gas pipeline investments include SNG, Horizon Pipeline, Atlantic Coast Pipeline, PennEast Pipeline, Dalton Pipeline, and Magnolia Enterprise Holdings, Inc. See Note 4 to the financial statements under "Equity Method Investments" for additional information.

Successor Year Ended December 31, 2017

Net income of $3 million includes $42 million in adjusted operating margin, $52 million in operating expenses, $103 million in earnings from equity method investments, consisting primarily of the Company's equity interest in SNG, including $33 million related to a non-cash charge recorded by SNG to establish a regulatory liability associated with the Tax Reform Legislation, and $4 million in other income, which resulted in EBIT of $97 million. Also included in net income are $33 million in interest expense, net of amounts capitalized and $61 million in income tax expense. Income tax expense includes $27 million resulting from the revaluation of deferred income tax assets associated with the Tax Reform Legislation and $8 million related to the allocation of new income tax apportionment factors in several states resulting from the Company's inclusion in the consolidated Southern Company state tax filings. See FUTURE EARNINGS POTENTIAL – "Income Tax Matters" herein and Note 5 to the financial statements for additional information on income taxes.

Successor Period of July 1, 2016 through December 31, 2016

Net income of $20 million includes $19 million in adjusted operating margin, $26 million in operating expenses, $58 million in earnings from equity method investments, consisting primarily of the Company's September 2016 acquired equity interest in SNG, and $1 million in other income, resulting in EBIT of $52 million. Also included in net income are $16 million in interest expense, net of amounts capitalized and $16 million in income tax expense.

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Predecessor Periods of January 1, 2016 through June 30, 2016 and the Year Ended December 31, 2015
Loss before interest and taxes for the predecessor periods of January 1, 2016 through June 30, 2016 and the year ended December 31, 2015 were $6 million and $23 million, respectively, and reflected a $14 million goodwill impairment charge in 2015.

All Other

All other includes the Company's investment in Triton, AGL Services Company, and Southern Company Gas Capital, as well as various corporate operating expenses that are not allocated to the reportable segments and interest income (expense) associated with affiliate financing arrangements.

Successor Year Ended December 31, 2017

Net loss of $140 million includes $10 million in adjusted operating margin and $47 million in operating expenses. Operating expenses included $26 million of integration-related costs. Interest expense, net of amounts capitalized was $2 million due to the intercompany promissory notes that were executed in December 2016. Income tax expense was $104 million and includes $86 million resulting from the revaluation of deferred tax assets associated with the Tax Reform Legislation and $29 million associated with State of Illinois tax legislation enacted during the third quarter 2017 and new income tax apportionment factors in several states resulting from the Company's inclusion in the consolidated Southern Company state tax filings. See FINANCIAL CONDITION AND LIQUIDITY – "Financing Activities" herein for additional financing information and FUTURE EARNINGS POTENTIAL – "Income Tax Matters" herein and Note 5 to the financial statements for additional information on income taxes.

Successor Period of July 1, 2016 through December 31, 2016

Operating expenses included Merger-related expenses of $41 million primarily comprised of compensation-related expenses, financial advisory fees, legal expenses, and other Merger-related costs and $8 million in expenses associated with certain benefit arrangements.

Predecessor Periods of January 1, 2016 through June 30, 2016 and the Year Ended December 31, 2015

For the predecessor periods of January 1, 2016 through June 30, 2016 and the year ended December 31, 2015, operating expenses included Merger-related expenses of $56 million and $44 million, respectively. These expenses are primarily comprised of financial advisory and legal expenses as well as additional compensation-related expenses, including acceleration of share-based compensation expenses, and change-in-control compensation charges. See Note 11 to the financial statements under "Merger with Southern Company" for additional information.

Segment Reconciliations

Reconciliations of net income attributable to Southern Company Gas to EBIT for the year ended December 31, 2017 and the period of July 1, 2016 through December 31, 2016, and operating income to adjusted operating margin for all periods presented, are in the following tables. See Note 12 to the financial statements for additional segment information.

| | Successor Year Ended December 31, 2017 | | | | | | |
|---|---|---|---|---|---|---|---|
| | Gas Distribution Operations | Gas Marketing Services | Wholesale Gas Services | Gas Midstream Operations | All Other | Intercompany Elimination | Consolidated |
| | (in millions) | | | | | | |
| Net Income (Loss) Attributable to Southern Company Gas | $353 | $ 84 | $ (57 ) | $ 3 | $(140) | $ — | $ 243 |
| Income taxes | 178 | 24 | — | 61 | 104 | — | 367 |
| Interest expense, net of amounts capitalized | 153 | 5 | 7 | 33 | 2 | — | 200 |
| EBIT | $684 | $ 113 | $ (50 ) | $ 97 | $(34 ) | $ — | $ 810 |

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| | Successor July 1, 2016 through December 31, 2016 | | | | | | |
|---|---|---|---|---|---|---|---|
| | Gas Distribution Operations | Gas Marketing Services | Wholesale Gas Services | Gas Midstream Operations | All Other | Intercompany Elimination | Consolidated |
| | (in millions) | | | | | | |
| Net Income (Loss) Attributable to Southern Company Gas | $77 | $ 19 | $ — | $ 20 | $(2) | $ — | $ 114 |
| Income taxes (benefit) | 51 | 7 | (3) | 16 | 5 | — | 76 |
| Interest expense, net of amounts capitalized | 105 | 1 | 3 | 16 | (44) | — | 81 |
| EBIT | $233 | $ 27 | $ — | $ 52 | $(41) | $ — | $ 271 |

| | Successor Year Ended December 31, 2017 | | | | | | |
|---|---|---|---|---|---|---|---|
| | Gas Distribution Operations | Gas Marketing Services | Wholesale Gas Services | Gas Midstream Operations | All Other | Intercompany Elimination | Consolidated |
| | (in millions) | | | | | | |
| Operating Income (Loss) | $650 | $ 113 | $ (51) | $ (10) | $(37) | $ — | $ 665 |
| Other operating expenses[(a)] | 1,282 | 200 | 56 | 52 | 47 | (12) | 1,625 |
| Revenue tax expense[(b)] | (98) | — | — | — | — | — | (98) |
| Adjusted Operating Margin | $1,834 | $ 313 | $ 5 | $ 42 | $10 | $ (12) | $ 2,192 |

| | Successor July 1, 2016 through December 31, 2016 | | | | | | |
|---|---|---|---|---|---|---|---|
| | Gas Distribution Operations | Gas Marketing Services | Wholesale Gas Services | Gas Midstream Operations | All Other | Intercompany Elimination | Consolidated |
| | (in millions) | | | | | | |
| Operating Income (Loss) | $222 | $ 27 | $ (2) | $ (7) | $(43) | $ — | $ 197 |
| Other operating expenses[(a)] | 626 | 112 | 26 | 26 | 46 | (4) | 832 |
| Revenue tax expense[(b)] | (31) | — | — | — | — | — | (31) |
| Adjusted Operating Margin | $817 | $ 139 | $ 24 | $ 19 | $3 | $ (4) | $ 998 |

| | Predecessor January 1, 2016 through June 30, 2016 | | | | | | |
|---|---|---|---|---|---|---|---|
| | Gas Distribution Operations | Gas Marketing Services | Wholesale Gas Services | Gas Midstream Operations | All Other | Intercompany Elimination | Consolidated |
| | (in millions) | | | | | | |
| Operating Income (Loss) | $351 | $ 109 | $ (69) | $ (9) | $(61) | $ — | $ 321 |
| Other operating expenses[(a)] | 616 | 81 | 33 | 24 | 65 | (4) | 815 |
| Revenue tax expense[(b)] | (56) | — | — | — | — | — | (56) |
| Adjusted Operating Margin | $911 | $ 190 | $ (36) | $ 15 | $4 | $ (4) | $ 1,080 |

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| | Predecessor Year Ended December 31, 2015 | | | | | | |
|---|---|---|---|---|---|---|---|
| | Gas Distribution Operations | Gas Marketing Services | Wholesale Gas Services | Gas Midstream Operations | All Other | Intercompany Elimination | Consolidated |
| | (in millions) | | | | | | |
| Operating Income (Loss) | $571 | $ 152 | $ 112 | $ (26) | $(63) | $ — | $ 746 |
| Other operating expenses[(a)] | 1,187 | 165 | 71 | 62 | 70 | (5) | 1,550 |
| Revenue tax expense[(b)] | (101) | — | — | — | — | — | (101) |
| Adjusted Operating Margin | $1,657 | $ 317 | $ 183 | $ 36 | $7 | $ (5) | $ 2,195 |

(a) Includes other operations and maintenance, depreciation and amortization, taxes other than income taxes, goodwill impairment in 2015, and Merger-related expenses.
(b) Nicor Gas' revenue tax expenses, which are passed through directly to customers.

## FUTURE EARNINGS POTENTIAL

### General

The results of operations for the past three years are not necessarily indicative of future earnings potential. The level of the Company's future earnings depends on numerous factors that affect the opportunities, challenges, and risks of the Company's primary business of natural gas distribution and its complementary businesses in the gas marketing services, wholesale gas services, and gas midstream operations sectors. These factors include the Company's ability to maintain a constructive regulatory environment that allows for the timely recovery of prudently-incurred costs, the completion and subsequent operation of ongoing infrastructure and other construction projects, creditworthiness of customers, the Company's ability to optimize its transportation and storage positions, and its ability to re-contract storage rates at favorable prices.

Future earnings will be driven primarily by customer growth and 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 price of natural gas, the price elasticity of demand, and the rate of economic growth or decline in the Company's service territories. Demand for 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.

Volatility of natural gas prices has a significant impact on the Company's customer rates, long-term competitive position against other energy sources, and the ability of its gas marketing services and wholesale gas services segments to capture value from locational and seasonal spreads. Additionally, changes in commodity prices subject a significant portion of the Company's operations to earnings variability. Over the longer term, volatility is expected to be low to moderate and locational and/or transportation spreads are expected to decrease as new pipelines are built to reduce the existing supply constraints in the shale areas of the Northeast U.S. To the extent these pipelines are delayed or not built, volatility could increase. Additional economic factors may contribute to this environment, including a significant drop in oil and natural gas prices, which could lead to consolidation of natural gas producers or reduced levels of natural gas production. Further, if economic conditions continue to improve, including the new housing market, the demand for natural gas may increase, which may cause natural gas prices to rise and drive higher volatility in the natural gas markets on a longer-term basis.

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. On July 6, 2017, the State of Illinois enacted tax legislation that repealed its non-combination tax rule and increased the effective corporate income tax rate effective July 1, 2017. In addition, Southern Company calculated new apportionment factors in several states to include the Company in its consolidated tax filings. See "Income Tax Matters" and FINANCIAL CONDITION AND LIQUIDITY – "Credit Rating Risk" herein and Notes 3 and 5 to the financial statements for additional information.

As part of its business strategy, the Company regularly considers and evaluates joint development arrangements as well as acquisitions and dispositions of businesses and assets. On October 15, 2017, the Company's 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.; the asset sales are expected to be completed by the end of the third quarter 2018. Net income attributable to Elizabethtown Gas and Elkton Gas for the year ended December 31, 2017 was $34 million. However, due to the seasonal nature of the natural gas business and other factors including, but not limited to, weather, regulation, competition, customer demand, and general economic conditions, the 2017 net income is not necessarily indicative of the results to be expected for any other period. See BUSINESS – "Seasonality" in Item 1, RISK FACTORS in Item 1A, and Note 11 to the financial statements under "Proposed Sale of Elizabethtown Gas and Elkton Gas" for additional information.

Environmental Matters

The Company'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 Company 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 results of operations, cash flows, and financial condition. 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 and the outcome of pending and/or future legal challenges.

New or revised environmental laws and regulations could affect many areas of the Company's 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. Further, increased costs that are recovered through regulated rates could contribute to reduced demand for 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 natural gas. See Note 3 to the financial statements under "Environmental Matters" for additional information.

Environmental Remediation

The Company is subject to environmental remediation liabilities associated with 46 former MGP sites in five different states. The Company conducts studies to determine the extent of any required cleanup and has recognized the costs to clean up known impacted sites in its financial statements. Accrued environmental remediation costs totaling $388 million were included in the balance sheets at December 31, 2017, $46 million of which is expected to be incurred over the next 12 months. The natural gas distribution utilities in Illinois, New Jersey, Georgia, and Florida have all received authority from their respective state regulators to recover approved environmental compliance costs through regulatory mechanisms, which covers substantially all of the total accrued remediation costs. See FINANCIAL CONDITION AND LIQUIDITY – "Capital Requirements and Contractual Obligations" herein for additional information.

Water Quality

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 Clean Water Act programs. The rule significantly expanded the scope of federal jurisdiction over waterbodies (such as rivers, streams, and canals), which could impact permitting and reporting requirements associated with the installation, expansion, and maintenance of 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.

FERC Matters

The Company is involved in two significant pipeline construction projects within gas midstream operations. These projects, along with the Company's 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. The following table provides an overview of these pipeline projects.

| | Miles of Pipe | Capital Expenditures | Ownership Interest |
|---|---|---|---|
| | | (in millions) | |
| Atlantic Coast Pipeline[a][b] | 594 | $ 310 | 5 % |
| PennEast Pipeline[a][c] | 118 | 276 | 20 % |
| Total | 712 | $ 586 | |

(a) Represents the Company's expected capital expenditures and ownership interest, which may change.

(b) In 2014, the Company entered into a joint venture to construct and operate a natural gas pipeline that will run from West Virginia through Virginia and into eastern North Carolina to meet the region's growing demand for natural gas. The proposed pipeline project is expected to transport natural gas to customers in Virginia. On October 13, 2017, the Atlantic Coast Pipeline project received FERC approval. The joint venture continues to work with state and other federal agencies to obtain the required environmental permits to begin construction.

(c) In 2014, the Company entered into a joint venture to construct and operate a natural gas pipeline that will transport low-cost natural gas from the Marcellus Shale area to customers in New Jersey. The Company believes this will alleviate takeaway constraints in the Marcellus region and help mitigate some of the price volatility experienced during recent winters. On January 19, 2018, the PennEast Pipeline project received FERC approval. The joint venture continues to work with state and other federal agencies to obtain the required environmental permits to begin construction.

On August 1, 2017, the Dalton Pipeline, which serves as an extension of the Transco pipeline system and provides additional natural gas supply to customers in Georgia, was placed in service. The Company has a 50% ownership interest in the Dalton Pipeline. See Note 4 to the financial statements for additional information.

On January 16, 2018, the Georgia PSC approved SNG's purchase of Georgia Power Company's natural gas lateral pipeline serving Plant McDonough Units 4 through 6 at net book value. Pursuant to this approval, legal transfer of the lateral pipeline is expected to occur in the fourth quarter 2018 and payment of $142 million is expected to occur in the first quarter 2020. During this interim period, Georgia Power Company will receive a discounted shipping rate to reflect the delayed consideration. Completion of this sale is contingent on certain conditions being satisfied by SNG that include, among other things, expansion of the existing lateral pipeline. The Company's portion of the expected capital expenditures for this project is $120 million. On February 15, 2018, FERC approval was obtained. The ultimate outcome of this matter cannot be determined at this time.

## Regulatory Matters

### Utility Regulation and Rate Design

The natural gas distribution utilities are subject to regulations and oversight by their respective state regulatory agencies for the rates charged to their customers, maintenance of accounting records, and various service and safety matters. Rates charged to customers vary according to customer class (residential, commercial, or industrial) and rate jurisdiction. 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. Rate base generally consists of the original cost of the utility plant in service, working capital, and certain other assets, less accumulated depreciation on the utility plant in service and net deferred income tax liabilities, and may include certain other additions or deductions.

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. The Marketers file their rates monthly with the Georgia PSC. As a result of operating in a deregulated environment, Atlanta Gas Light's role includes:

- distributing natural gas for Marketers;

- constructing, operating, and maintaining the gas system infrastructure, including responding to customer service calls and leaks;
- reading meters and maintaining underlying customer premise information for Marketers; and
- planning and contracting for capacity on interstate transportation and storage systems.

Atlanta Gas Light earns revenue by charging rates to its customers based primarily on monthly fixed charges that are set by the Georgia PSC and adjusted periodically. The Marketers add these fixed charges when billing customers. This mechanism, called a straight-fixed-variable rate design, minimizes the seasonality of Atlanta Gas Light's revenues since the monthly fixed charge is not volumetric or directly weather dependent.

With the exception of Atlanta Gas Light, the earnings of the natural gas distribution utilities can be affected by customer consumption patterns that are largely a function of weather conditions and price levels for natural gas. Specifically, customer demand substantially increases during the Heating Season when natural gas is used for heating purposes. The Company has various mechanisms, such as weather normalization mechanisms and weather derivative instruments, at most of its utilities that limit exposure to weather changes within typical ranges in these utilities' respective service territories.

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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. Since Atlanta Gas Light does not sell natural gas directly to its end-use customers, it does not utilize a traditional natural gas cost recovery mechanism. However, Atlanta Gas Light does maintain natural gas inventory for the Marketers in Georgia and recovers the cost through recovery mechanisms approved by the Georgia PSC specific to Georgia's deregulated market. In addition to natural gas 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. In traditional rate designs, utilities recover a significant portion of the fixed customer service and pipeline infrastructure costs based on assumed natural gas volumes used by customers. Three of the utilities have decoupled regulatory mechanisms that the Company believes encourage conservation by separating the recoverable amount of these fixed costs from the amounts of natural gas used by 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 the Company's revenues or net income, but will affect cash flows. See Note 3 to the financial statements under "Regulatory Matters" for additional information.

The following table provides regulatory information for the Company's six largest natural gas distribution utilities:

| | Nicor Gas | Atlanta Gas Light | Elizabethtown Gas | Virginia Natural Gas | Florida City Gas | Chattanooga Gas |
|---|---|---|---|---|---|---|
| Authorized ROE[(a)(b)] | 9.80% | 10.75% | 9.60% | 9.50% | 11.25% | 10.05% |
| Weather normalization[(c)] | | | ü | ü | | ü |
| Decoupled, including straight-fixed-variable rates[(d)] | | ü | | ü | | ü |
| Regulatory infrastructure program rates[(e)] | ü | | | ü | ü | |
| Bad debt rider[(f)] | ü | | | ü | | ü |
| Energy efficiency plan[(g)] | ü | | ü | ü | ü | ü |
| Last decision on change in rates[(h)] | 2018 | 2017 | 2017 | 2017 | 2004 | 2010 |

(a) Represents the authorized ROE, or the midpoint of the authorized ROE range, at December 31, 2017, except Nicor Gas which represents the authorized ROE established in the January 31, 2018 order issued by the Illinois Commission. The authorized ROE of Nicor Gas at December 31, 2017 was 10.17%. See "Base Rate Cases" herein and Note 3 to the financial statements under "Regulatory Matters – Base Rate Cases" for additional information.

(b) The authorized ROE range for Atlanta Gas Light, Virginia Natural Gas, and Florida City Gas was 10.55% - 10.95%, 9.00% - 10.00%, and 10.25% - 12.25%, respectively, at December 31, 2017.

(c) Regulatory mechanisms that allow recovery of costs in the event of unseasonal weather, but are not direct offsets to the potential impacts on earnings of weather and customer consumption. These mechanisms are designed to help stabilize operating results by increasing base rate amounts charged to customers when weather is warmer than normal and decreasing amounts charged when weather is colder than normal.

(d) Recovery of fixed customer service costs separately from assumed natural gas volumes used by customers.

(e) Programs that update or expand distribution systems and LNG facilities.

(f) The recovery (refund) of bad debt expense over (under) an established benchmark expense. Virginia Natural Gas and Chattanooga Gas recover the gas portion of bad debt expense through their purchased gas adjustment mechanisms.

(g) Recovery of costs associated with plans to achieve specified energy savings goals.

(h) See "Base Rate Cases" herein and Note 3 to the financial statements under "Regulatory Matters – Base Rate Cases" for additional information.

Infrastructure Replacement Programs and Capital Projects

The Company continues to focus on capital discipline and cost control while pursuing projects and initiatives that are expected to have current and future benefits to customers, provide an appropriate return on invested capital, and help ensure the safety and reliability of the utility infrastructure. Total capital expenditures incurred during 2017 for gas distribution operations were $1.3 billion. The following table and discussions provide updates on the infrastructure replacement programs at the natural gas distribution utilities, which are designed to update or expand the Company's distribution systems to improve reliability and meet operational flexibility and growth. The anticipated expenditures for these programs in 2018 are quantified in the discussion below.

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| Utility | Program | Program Details | Recovery | Expenditures in 2017 | Expenditures Since Project Inception | Miles of Pipe Installed Since Project Inception | Scope of Program | Program Duration | Last Year of Program |
|---|---|---|---|---|---|---|---|---|---|
| | | | | (in millions) | | | (miles) | (years) | |
| Nicor Gas | Investing in Illinois | (a)(b) | Rider | $336 | $ 907 | 516 | 800 | 9 | 2023 |
| Atlanta Gas Light | Integrated Vintage Plastic Replacement Program (i-VPR) | (c)(i) | Base Rates | 50 | 251 | 782 | 756 | 4 | 2017 |
| Atlanta Gas Light | Integrated System Reinforcement Program (i-SRP) | (g)(i) | Base Rates | 76 | 446 | n/a | n/a | 8 | 2017 |
| Atlanta Gas Light | Integrated Customer Growth Program (i-CGP) | (h)(i) | Base Rates | 18 | 89 | n/a | n/a | 8 | 2017 |
| Chattanooga Gas | Bare Steel & Cast Iron | (e) | Base Rates | 3 | 43 | 94 | 111 | 10 | 2020 |
| Florida City Gas | Safety, Access and Facility Enhancement Program (SAFE) | (d) | Rider | 10 | 21 | 64 | 250 | 10 | 2025 |
| Florida City Gas | Galvanized Replacement Program | (f) | Base Rates | — | 16 | 80 | 111 | 17 | 2017 |
| Virginia Natural Gas | Steps to Advance Virginia's Energy (SAVE and SAVE II) | (a) | Rider | 34 | 156 | 255 | 496 | 10 | 2021 |
| Elizabethtown Gas | Aging Infrastructure Replacement (AIR) | (e) | Base Rates | 16 | 115 | 96 | 130 | 4 | 2017 |
| Total | | | | $543 | $ 2,044 | 1,887 | 2,654 | | |

(a) Replacement of cast iron, bare steel, mid-vintage plastic, and risk-based materials.
(b) Represents expenditures on qualifying infrastructure placed into service after December 9, 2014.
(c) Replacement of early vintage plastic, risk-based mid-vintage plastic, and mid-vintage neighborhood convenience.
(d) Replacement of four-inch and smaller mains, associated service lines, and in some instances above-ground facilities associated with rear-lot easements.
(e) Replacement of cast iron and bare steel pipes.
(f) Replacement of galvanized and X-Tube steel pipes. Reflects expenditures and miles of pipe installed since the Company acquired Florida City Gas in 2004.
(g) Installation of large diameter pressure improvement and system reinforcement projects.
(h) Installation of new business construction and strategic line extension.
(i) Recovery of the related program costs was incorporated in Atlanta Gas Light's petition for GRAM, which the Georgia PSC approved on February 21, 2017. See "Base Rate Cases" herein and Note 3 to the financial statements under "Regulatory Matters – Base Rate Cases" for additional information.

Nicor Gas
In 2013, Illinois enacted legislation that allows Nicor Gas to provide more widespread safety and reliability enhancements to its distribution system. The legislation stipulates that rate increases to customers as a result of any infrastructure investments shall not exceed a cumulative annual average of 4.0% or, in any given year, 5.5% of base rate revenues. In 2014, the Illinois

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Commission approved the nine-year regulatory infrastructure program, Investing in Illinois, under which Nicor Gas implemented rates that became effective in March 2015. Nicor Gas expects to place into service $350 million of qualifying projects under Investing in Illinois in 2018.

Investing in Illinois is subject to annual review by the Illinois Commission. In conjunction with the base rate case order issued by the Illinois Commission on January 31, 2018, Nicor Gas is recovering the portion of these program costs incurred prior to December 31, 2017 through base rates. See "Base Rate Cases" herein for additional information.

Atlanta Gas Light

Atlanta Gas Light's STRIDE program, which was initially approved by the Georgia PSC in 2009, is comprised of i-SRP, i-CGP, and i-VPR, and consists of infrastructure development, enhancement, and replacement programs that are used to update and expand distribution systems and LNG facilities, improve system reliability, and meet operational flexibility and growth. For 2017 and subsequent years, the recovery of and return on current and future capital investments under the STRIDE program are included in the annual base rate revenue adjustment under GRAM.

The i-CGP program authorized Atlanta Gas Light to spend $91 million through 2017 on projects to extend its pipeline facilities to serve customers in areas without pipeline access and create new economic development opportunities in Georgia. This program ended in 2017 and was replaced with a tariff to provide up to $15 million annually for Atlanta Gas Light to commit to strategic economic development projects.

The i-SRP program authorized $445 million of capital spending through 2017 for projects to upgrade Atlanta Gas Light's distribution system and LNG facilities in Georgia, improve its peak-day system reliability and operational flexibility, and create a platform to meet long-term forecasted growth. In August 2016, Atlanta Gas Light filed a petition with the Georgia PSC for approval of a four-year extension of its i-SRP seeking approval to invest an additional $177 million to improve and upgrade its core gas distribution system in years 2017 through 2020.

The i-VPR program authorized Atlanta Gas Light to spend $275 million through 2017 to replace 756 miles of aging plastic pipe that was installed primarily in the mid-1960s to the early 1980s. Atlanta Gas Light has identified approximately 3,300 miles of vintage plastic mains in its system that should be considered for potential replacement. See "Base Rate Cases" herein for additional information on GRAM.

Elizabethtown Gas

Elizabethtown Gas' 2013 extension of the AIR enhanced infrastructure program allowed for infrastructure investment of $115 million over four years and was focused on the replacement of aging cast iron in its pipeline system. Carrying charges on the additional capital spend are being accrued and deferred for regulatory purposes at a weighted average cost of capital of 6.65%. Effective July 1, 2017, investments under this program, which ended September 30, 2017, are being recovered through base rate revenues. See "Base Rate Cases" herein for additional information.

In 2015, Elizabethtown Gas filed the Safety, Modernization and Reliability Tariff plan with the New Jersey BPU seeking approval to invest more than $1.1 billion to replace 630 miles of vintage cast iron, steel, and copper pipeline, as well as 240 regulator stations. During the first quarter 2018, Elizabethtown Gas withdrew this filing in response to a proposed rule by the New Jersey BPU to incentivize utilities to accelerate investment in infrastructure replacement programs that enhance reliability, resiliency, and/or safety of the distribution system. Elizabethtown Gas expects to file a revised plan during the second half of 2018. The ultimate outcome of this matter cannot be determined at this time.

Virginia Natural Gas

In 2012, the Virginia Commission approved the SAVE program, an accelerated infrastructure replacement program, to be completed over a five-year period. This program included a maximum allowance for capital expenditures of $25 million per year, not to exceed $105 million in total.

In March 2016, the Virginia Commission approved an extension to the SAVE program for Virginia Natural Gas to replace more than 200 miles of aging pipeline infrastructure and invest up to $30 million in 2016 and up to $35

million annually through 2021. Virginia Natural Gas expects to invest $35 million under this program in 2018.
The SAVE program is subject to annual review by the Virginia Commission. In conjunction with the base rate case order issued by the Virginia Commission on December 21, 2017, Virginia Natural Gas is recovering the portion of these program costs incurred prior to September 1, 2017 through base rates. See "Base Rate Cases" herein for additional information.

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Florida City Gas

In 2015, the Florida PSC approved Florida City Gas' SAFE, under which costs incurred for replacing aging pipes are recovered through a rate rider with annual adjustments and true-ups. Under the program, Florida City Gas is authorized to spend $105 million over a 10-year period on infrastructure relocation and enhancement projects. Florida City Gas expects to invest $10 million under this program in 2018.

PRP Settlement

In 2015, Atlanta Gas Light received a final order from the Georgia PSC for a rate true-up of allowed unrecovered revenue through 2014 related to its PRP. This order allows Atlanta Gas Light to recover $144 million of the $178 million previously unrecovered program revenue. The remaining $34 million requested related primarily to previously unrecognized ratemaking amounts and did not have a material impact on the Company's financial statements. The Company also recognized $1 million of interest expense and $5 million in operations and maintenance expense related to the PRP on the Company's statements of income for the predecessor year ended December 31, 2015. See "Unrecognized Ratemaking Amounts" herein for additional information.

As a result of the PRP settlement, Atlanta Gas Light began recovering incremental PRP surcharge amounts through three phased in increases in addition to its already existing PRP surcharge amount, which was established to address recovery of the unrecovered PRP balance of $144 million in 2015 and the estimated amounts to be earned under the program through 2025. The initial incremental surcharge of approximately $15 million annually was effective in October 2015, with additional annual increases of approximately $15 million in each of October 2016 and 2017. The final increase scheduled for October 2017 was included in the implementation of GRAM in March 2017. The under recovered balance is the result of the continued revenue requirement earned under the program offset by the existing and incremental PRP surcharges. The unrecovered balance at December 31, 2017 was $187 million, including $104 million of unrecognized equity return. The PRP surcharge will remain in effect until the earlier of the full recovery of the under recovered amount or December 31, 2025. See "Base Rate Cases" herein for additional information on GRAM.

One of the capital projects under the PRP experienced construction issues and Atlanta Gas Light was required to complete mitigation work prior to placing it in service. These mitigation costs will be included in future base rates in 2018. Provisions in the order resulted in the recognition of $5 million in operations and maintenance expense for the predecessor year ended December 31, 2015 on the Company's statements of income. In 2017, Atlanta Gas Light recovered $20 million from the settlement of contractor litigation claims and continues to pursue contractual and legal claims against a third-party contractor. Mitigation costs recovered through the legal process are retained by Atlanta Gas Light. The ultimate outcome of this matter cannot be determined at this time.

Base Rate Cases

Settled Base Rate Cases

On February 21, 2017, the Georgia PSC approved GRAM and a $20 million increase in annual base rate revenues for Atlanta Gas Light, effective March 1, 2017. GRAM adjusts base rates annually, up or down, using an earnings band based on the previously approved ROE of 10.75% and does not collect revenue through special riders and surcharges. Atlanta Gas Light adjusts rates up to the lower end of the band of 10.55% and adjusts rates down to the higher end of the band of 10.95%. Various infrastructure programs previously authorized by the Georgia PSC under Atlanta Gas Light's STRIDE program, which include i-VPR and i-SRP, will continue under GRAM and the recovery of and return on the infrastructure program investments will be included in annual base rate adjustments. The Georgia PSC will review Atlanta Gas Light's performance annually under GRAM.

Pursuant to the GRAM approval, Atlanta Gas Light and the staff of the Georgia PSC agreed to a variation to the i-CGP that was formerly part of Atlanta Gas Light's STRIDE program. As a result, a new tariff was created, effective October 10, 2017, to provide up to $15 million annually for Atlanta Gas Light to commit to strategic economic development projects. Projects under this tariff must be approved by the Georgia PSC.

Beginning with the next rate adjustment in June 2018, Atlanta Gas Light's recovery of the previously unrecovered Pipeline Replacement Program revenue through 2014, as well as the mitigation costs associated with the Pipeline Replacement Program that were not previously included in its rates, will also be included in GRAM. In connection with the GRAM approval, the last monthly Pipeline Replacement Program surcharge increase became effective March 1, 2017.

On June 30, 2017, the New Jersey BPU approved a settlement that provides for a $13 million increase in annual base rate revenues, effective July 1, 2017, based on a ROE of 9.6%. Also included in the settlement was a new composite depreciation rate that is expected to result in a $3 million annual reduction of depreciation. See Note 11 to the financial statements under "Proposed Sale of Elizabethtown Gas and Elkton Gas" for information on the proposed sale of Elizabethtown Gas.

On December 21, 2017, the Virginia Commission approved a settlement for a $34 million increase in annual base rate revenues, effective September 1, 2017, including $13 million related to the recovery of investments under the SAVE program. See "Infrastructure Replacement Programs and Capital Projects" herein for additional information. An authorized ROE range of 9.0% to 10.0% with a midpoint of 9.5% will be used to determine the revenue requirement in any filing, other than for a change in base rates.

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

Pending Base Rate Cases

On October 23, 2017, Florida City Gas filed a general base rate case with the Florida PSC requesting a $19 million increase in annual base rate revenues. On January 29, 2018, Florida City Gas filed an update to incorporate the effects of the Tax Reform Legislation that, if approved, would reduce the requested base rate revenues by $4 million. The requested increase is based on a 2018 projected test year and a ROE of 11.25%. The requested increase includes $3 million related to the recovery of investments under SAFE that are currently being recovered through a surcharge. Additionally, Florida City Gas requested an interim rate increase of $5 million annually that was approved and became effective January 12, 2018, subject to refund. The Florida PSC is expected to rule on the requested increase in mid-2018.

On December 1, 2017, Atlanta Gas Light filed its 2018 annual rate adjustment with the Georgia PSC. If approved, 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.

On February 15, 2018, Chattanooga Gas filed a general base rate case with the Tennessee Public Utility Commission requesting a $7 million increase in annual base rate revenues. The requested increase, which incorporated the effects of the Tax Reform Legislation, was based on a projected test year ending June 30, 2019 and a ROE of 11.25%. The Tennessee Public Utility Commission is expected to rule on the requested increase in the third quarter 2018.

The ultimate outcome of these pending base rate cases cannot be determined at this time.

Other

The New Jersey BPU, Virginia Commission, Tennessee Public Utility Commission, and Maryland PSC each issued an order effective January 1, 2018 that requires utilities in their respective states to track as a regulatory liability the impact of the Tax Reform Legislation, including the reduction in the corporate income tax rate to 21% and the impact of excess deferred income taxes. The New Jersey BPU's order requires Elizabethtown Gas to file by March 2, 2018 proposed revised base rates with an April 1, 2018 interim effective date and a July 1, 2018 final effective date. Virginia Natural Gas will address the Virginia Commission's order in its Annual Information Filing, which will be filed by July 1, 2018. The Tennessee Public Utility Commission's order required Chattanooga Gas to file proposals to reduce rates or make other ratemaking adjustments to account for the impact of the Tax Reform Legislation. Chattanooga Gas made the required filing as part of its February 15, 2018 general base rate case filing. The Maryland PSC's order required Elkton Gas to file an explanation of the impact of the Tax Reform Legislation on its expenses and revenues, as well as when and how it expects to pass through to its customers those effects. Elkton Gas made the required filing on February 15, 2018 and will reduce annual base rates by $0.1 million effective April 1, 2018. Credits will be issued to customers for the impact of the Tax Reform Legislation from January 2018 through March 2018.

The Illinois 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 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.

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

Asset Management Agreements

All of the natural gas distribution utilities except Nicor Gas use asset management agreements with the Company's wholly-owned subsidiary, Sequent, for the primary purpose of reducing utility customers' gas cost recovery rates through payments to the utilities by Sequent. For Atlanta Gas Light, these payments are controlled by the Georgia PSC and are utilized for infrastructure improvements and to fund heating assistance programs, rather than as a reduction to gas cost recovery rates. Under these asset management agreements, Sequent supplies natural gas to the utility and markets available pipeline and storage capacity to improve the overall cost of supplying gas to the utility customers. Currently, the Company's utilities primarily purchase their gas from Sequent. The purchase agreements require Sequent to provide firm gas to the natural gas distribution utilities, but these natural gas distribution utilities maintain the right and ability to make their own long-term supply arrangements if they believe it is in the best interest of their customers.

Each agreement provides for Sequent to make payments to the natural gas distribution utilities through either an annual minimum guarantee within a profit sharing structure, a profit sharing structure without an annual minimum guarantee, or a fixed fee. From the inception of these agreements in 2001 through December 31, 2017, Sequent made sharing payments to the natural gas distribution utilities under these agreements totaling $390 million.

The following table provides payments made by Sequent to the natural gas distribution utilities under these agreements during the last three years:

| | Successor Total Amount Received | | Predecessor Total Amount Received | | |
|---|---|---|---|---|---|
| | Year Ended December 31, 2017 | July 1, 2016 through December 31, 2016 | January 1, 2016 through June 30, 2016 | Year Ended December 31, 2015 | Expiration Date |
| | (in millions) | | (in millions) | | |
| Elizabethtown Gas | $ 11 | $ 3 | $ 12 | $ 28 | March 2019 |
| Virginia Natural Gas | 6 | 2 | 9 | 15 | March 2019 |
| Atlanta Gas Light | 4 | 1 | 6 | 15 | March 2020 |
| Florida City Gas | 1 | — | 1 | 1 | (a) |
| Chattanooga Gas | 1 | — | 1 | 1 | March 2021 |
| Total(b) | $ 23 | $ 6 | $ 29 | $ 60 | |

(a) The agreement renews automatically each year unless terminated by either party.
(b) Payments made to Elkton Gas were less than $1 million for each of the periods presented.

Upon consummation of the asset sales of Elizabethtown Gas and Elkton Gas, South Jersey Industries, Inc. will assume the asset management agreements of Elizabethtown Gas and Elkton Gas. See Note 11 to the financial statements under "Proposed Sale of Elizabethtown Gas and Elkton Gas" for additional information on these sales.

energySMART

In 2014, the Illinois Commission approved Nicor Gas' energySMART through 2017, which outlined energy efficiency program offerings and therm reduction goals, and subsequently extended the program to 2021. Through December 31, 2017, Nicor Gas spent $107 million of the initial authorized expenditure of $113 million. A new four-year program began on January 1, 2018, with an additional authorized expenditure of $160 million. Nicor Gas expects to invest $40 million under this program in 2018.

Unrecognized Ratemaking Amounts

The following table illustrates the Company's authorized ratemaking amounts that are not recognized on its balance sheets. These amounts are primarily composed of an allowed equity rate of return on assets associated with certain of the Company's regulatory infrastructure programs. These amounts will be recognized as revenues in the Company's financial statements in the periods they are billable to customers, the majority of which will be recovered by 2025.

| | December 31, 2017 | December 31, 2016 |
|---|---|---|
| | (in millions) | |

| | | |
|---|---|---|
| Atlanta Gas Light | $ 104 | $ 110 |
| Virginia Natural Gas | 11 | 11 |
| Elizabethtown Gas(*) | 8 | 6 |
| Nicor Gas | 2 | 2 |
| Total | $ 125 | $ 129 |

(*) See Note 11 to the financial statements under "Proposed Sale of Elizabethtown Gas and Elkton Gas" for information on the pending asset sale.

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 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 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.

For the year ended December 31, 2017, implementation of the Tax Reform Legislation resulted in an estimated net tax expense of $93 million and a $777 million increase in regulatory liabilities, primarily due to the impact of the reduction of the corporate income tax rate on deferred tax assets and liabilities.

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 Tax Reform Legislation is subject to the discretion of the FERC and the relevant state regulatory bodies as further described in Note 3 to the financial statements under "Base Rate Cases" and "Other" for additional information.

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 $200 million for the 2017 tax year and approximately $60 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. See Note 5 to the financial statements under "Current and Deferred Income Taxes" for additional information. The ultimate outcome of this matter cannot be determined at this time.

State Tax Reform Legislation

On July 6, 2017, the State of Illinois enacted tax legislation that repealed its non-combination tax rule and increased the effective corporate income tax rate from 5.25% to 7.0% (making the total corporate tax rate 9.5% when combined with the 2.5% personal property replacement tax) effective July 1, 2017. In addition to increasing taxes on future earnings, this legislation required the Company to increase accumulated deferred income tax liabilities by $24 million during the third quarter 2017 to reflect these changes, of which $15 million was expensed and $9 million was recorded as a regulatory asset.

Change in State Apportionment Factors

Southern Company calculated new apportionment factors in several states to include the Company in its consolidated tax filings, which resulted in $22 million of additional deferred income tax expenses in the successor year ended December 31, 2017.

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Other Matters

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

Nicor Gas and Nicor Energy Services Company, wholly-owned subsidiaries of the Company, and Nicor Inc. were defendants in a putative class action initially filed in 2011 in the state court in Cook County, Illinois. The plaintiffs purported to represent a class of the customers who purchased the Gas Line Comfort Guard product from Nicor Energy Services Company and variously alleged that the marketing, sale, and billing of the Gas Line Comfort Guard product violated the Illinois Consumer Fraud and Deceptive Business Practices Act, constituting common law fraud and resulting in unjust enrichment of these entities. The plaintiffs sought, on behalf of the classes they purported to represent, actual and punitive damages, interest, costs, attorney fees, and injunctive relief. On February 8, 2017, the judge denied the plaintiffs' motion for class certification and the Company's motion for summary judgment. On March 7, 2017, the parties reached a settlement, which was finalized and effective on April 3, 2017. The settlement did not have a material impact on the Company's financial statements.

The Company is assessing its alleged involvement in an incident that occurred in one of its service territories that resulted in several deaths, injuries, and property damage. One of the natural gas distribution utilities has been named as one of the defendants in several lawsuits related to this incident. The Company has insurance that provides full coverage of any financial exposure in excess of $11 million per incident. During the successor period ended December 31, 2016 and the predecessor period ended December 31, 2015, the Company recorded reserves for substantially all of its potential exposure from these cases.

The ultimate outcome of these matters and 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 the Company's financial statements. See Note 3 to the financial statements under "General Litigation Matters" for a discussion of various other contingencies, regulatory matters, and other matters being litigated which may affect future earnings potential.

The Company owns a 50% interest in a planned LNG liquefaction and storage facility in Jacksonville, Florida. Once construction is complete and the facility is operational, it will be outfitted with a 2.0 million gallon storage tank with the capacity to produce in excess of 120,000 gallons of LNG per day. It is expected to be operational in the first half of 2018. The ultimate outcome of this matter cannot be determined at this time.

A wholly-owned subsidiary of the Company 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 the Company 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. The Company 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 the Company's 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 material impact on the Company's financial statements.

Effective January 1, 2018, the Company conformed its paid time off policy to align with Southern Company. Under the new policy, paid time off days are vested by the employee on the first day of each year and will continue to be recovered through rates on an as-paid basis. As a result, the Company accrued $21 million as of January 1, 2018, of which $9 million was recorded as a regulatory asset.

ACCOUNTING POLICIES

Application of Critical Accounting Policies and Estimates

The Company prepares its financial statements in accordance with GAAP. Significant accounting policies are described in Note 1 to the financial statements. In the application of these policies, certain estimates are made that may have a material impact on the

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Company's results of operations and related disclosures. Different assumptions and measurements could produce estimates that are significantly different from those recorded in the financial statements. Senior management has reviewed and discussed the following critical accounting policies and estimates with the Audit Committee of Southern Company's Board of Directors.

Utility Regulation

The natural gas distribution utilities comprised approximately 82% of the Company's total operating revenues for 2017 and are subject to rate regulation by their respective state regulatory agencies, which set the rates utilities are permitted to charge customers based on allowable costs, including a reasonable ROE. As a result, 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 natural gas distribution utilities; therefore, the accounting estimates inherent in specific costs such as depreciation and pension and other postretirement benefits have less of a direct impact on the Company's results of operations and financial condition than they would on a non-regulated company.

As reflected in Note 1 to the financial statements, significant regulatory assets and liabilities have been recorded. Management reviews the ultimate recoverability of these regulatory assets and any requirement to refund these regulatory liabilities based on applicable regulatory guidelines and GAAP. However, adverse legislative, judicial, or regulatory actions could materially impact the amounts of such regulatory assets and liabilities and could adversely impact the Company's financial statements.

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 many states in which the Company operates.

On behalf of the Company, 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 carryforwards and the assessment of valuation allowances are based on significant judgment and extensive analysis of the Company's, as well as Southern 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 the Company's financial statements.

Given the significant judgment involved in estimating NOL carryforwards and tax credit carryforwards and multi-state apportionments, the 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, the 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. The 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 liabilities cannot be determined at this time. See "Income Tax Matters – Federal Tax Reform Legislation" herein and Note 3 to the financial statements under "Base Rate Cases" and "Other" and Note 5 to the financial statements under "Current and Deferred Income Taxes" for additional information.

Assessment of Assets

Goodwill

The Company does not amortize its goodwill, but tests it annually for impairment at the reporting unit level during the fourth quarter or more frequently if impairment indicators arise. These indicators include, but are not limited to, a significant change in operating performance, the business climate, legal or regulatory factors, or a planned sale or disposition of a significant portion of the business. A reporting unit is the operating segment, or a business one level below the operating segment (a component), if discrete financial information is prepared and regularly reviewed by management. Components are aggregated if they have similar economic characteristics.

As part of the Company's impairment test, the Company may perform an initial qualitative Step 0 assessment to determine whether it is more likely than not that the fair value of each reporting unit is less than its carrying amount before applying the two-step, quantitative goodwill impairment test. If the Company elects to perform the qualitative assessment, it evaluates relevant events and circumstances, including but not limited to, macroeconomic conditions, industry and market conditions, cost factors, financial performance, entity specific events, and events specific to each reporting unit. If the Company determines that it is more likely than not that the fair value of a reporting unit is less than its carrying amount, or it elects not to perform a qualitative assessment, it performs the two-step goodwill impairment test.

Step 1 of the two-step goodwill impairment test compares the fair value of the reporting unit to its carrying value. If the result of the Step 1 test reveals that the estimated fair value is below its carrying value, the Company proceeds with Step 2.

Step 2 of the two-step goodwill impairment test compares the implied fair value of goodwill, which is calculated as the residual amount from the reporting unit's overall fair value after assigning fair values to its assets and liabilities under a hypothetical purchase price allocation as if the reporting unit had been acquired in a business combination, to its carrying value. Based on the result of the Step 2 test, the Company records a goodwill impairment charge for any excess of carrying value over the implied fair value of goodwill.

For the 2017 annual impairment test, the Company performed Step 1 of the two-step impairment test, which resulted in the fair value of all of its reporting units that have goodwill exceeding their carrying value. For the 2016 and 2015 annual impairment tests, the Company performed the qualitative Step 0 assessment and determined that it was more likely than not that the fair value of all of its reporting units with goodwill exceeded their carrying amounts, and therefore no quantitative analysis was required. In the third quarter 2015, the Company identified potential impairment indicators and performed an interim impairment test for its storage and fuels reporting unit, which resulted in impairment of the full $14 million goodwill balance for that reporting unit.

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, the Company considers these estimates to be critical accounting estimates.

See "Recently Issued Accounting Standards – Other" herein for information on the Company's adoption of ASU No. 2017-04 effective January 1, 2018.

Long-Lived Assets

The Company depreciates or amortizes its long-lived and intangible assets over their estimated useful lives. The Company assesses its long-lived and intangible assets for impairment whenever events or changes in circumstances indicate that an asset's carrying amount may not be recoverable. When such events or circumstances are present, the Company assesses the recoverability of long-lived assets by determining whether the carrying value will be recovered through the expected future cash flows. Impairment is indicated if the carrying amount of a long-lived asset exceeds the sum of the undiscounted future cash flows expected to result from the use and eventual disposition of the asset. If impairment is indicated, the Company records an impairment loss equal to the difference between the carrying value and the fair value of the long-lived asset.

As the determination of the expected future cash flows generated from an asset, 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, the Company considers these estimates to be critical accounting estimates.

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Derivatives and Hedging Activities

Determining whether a contract meets the definition of a derivative instrument, contains an embedded derivative requiring bifurcation, or qualifies for hedge accounting treatment is voluminous and complex. The treatment of a single contract may vary from period to period depending upon accounting elections, changes in the Company's assessment of the likelihood of future hedged transactions, or new interpretations of accounting guidance. As a result, judgment is required in determining the appropriate accounting treatment. In addition, the estimated fair value of derivative instruments may change significantly from period to period depending upon market conditions, and changes in hedge effectiveness may impact the accounting treatment.

Derivative instruments (including certain derivative instruments embedded in other contracts) are recorded on the balance sheets as either assets or liabilities measured at their fair value. If the transaction qualifies for, and is designated as, a normal purchase or normal sale, it is exempted from fair value accounting treatment and is, instead, subject to traditional accrual accounting. The 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.

Changes in the derivatives' fair value 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 recorded in OCI on the balance sheets until the hedged transaction affects earnings in the case of a cash flow hedge. Additionally, a company is required to formally designate a derivative as a hedge as well as document and assess the effectiveness of derivatives associated with transactions that receive hedge accounting treatment.

Nicor Gas and Elizabethtown Gas utilize derivative instruments to hedge the price risk for the purchase of natural gas for customers. These derivatives are reflected at fair value and are not designated as accounting hedges. Realized gains or losses on such instruments are included in the cost of gas delivered and are passed through directly to customers, subject to review by the applicable state regulatory agencies, and therefore have no direct impact on earnings. Unrealized changes in the fair value of these derivative instruments are deferred as regulatory assets or liabilities.

The Company uses derivative instruments primarily to reduce the impact to its results of operations due to the risk of changes in the price of natural gas and to a lesser extent the Company hedges against warmer-than-normal weather and interest rates. The fair value of natural gas derivative instruments used to manage exposure to changing natural gas prices reflects the estimated amounts that the Company would receive or pay to terminate or close the contracts at the reporting date, taking into account the current unrealized gains or losses on open contracts. For derivatives utilized at gas marketing services and wholesale gas services that are not designated as accounting hedges, changes in fair value are reported as gains or losses in the Company's results of operations in the period of change. Gas marketing services records derivative gains or losses arising from cash flow hedges in OCI and reclassifies them into earnings in the same period that the underlying hedged item is recognized in earnings.

The 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 the Company's nonperformance risk on its liabilities.

If there is a significant change in the underlying market prices or pricing assumptions the Company uses in pricing its derivative assets or liabilities, the Company may experience a significant impact on its financial position, results of operations, and cash flows. See Note 10 to the financial statements for additional information.

Given the assumptions used in pricing the derivative asset or liability, the 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.

Pension and Other Postretirement Benefits

The Company's calculation of pension and other postretirement benefits expense is dependent on a number of assumptions. These assumptions include discount rates, healthcare cost trend rates, expected long-term return on plan assets, mortality rates, expected salary and wage increases, and other factors. Components of pension and other postretirement benefits expense include interest and service cost on the pension and other postretirement benefit plans, expected return on plan assets, and amortization of certain unrecognized costs and obligations. Actual results that differ from the assumptions utilized are accumulated and amortized over

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future periods and, therefore, generally affect recognized expense and the recorded obligation in future periods. While the Company believes that the assumptions used are appropriate, differences in actual experience or significant changes in assumptions would affect its pension and other postretirement benefits costs and obligations.

Key elements in determining the Company's pension and other postretirement benefit expense are the expected long-term return on plan assets and the discount rate used to measure the benefit plan obligations and the periodic benefit plan expense for future periods. The expected long-term return on pension and other postretirement benefit plan assets is based on the Company's investment strategy, historical experience, and expectations for long-term rates of return that consider external actuarial advice. The Company determines the long-term return on plan assets by applying the long-term rate of expected returns on various asset classes to the Company's target asset allocation. For purposes of determining its liability related to the pension and other postretirement benefit plans, the Company discounts the future related cash flows using a single-point discount rate developed from the weighted average of market-observed yields for high quality fixed income securities with maturities that correspond to expected benefit payments. Prior to 2016, the Company computed the interest cost component of its net periodic pension and other postretirement benefit plan expense using the same single-point discount rate. In 2016, the Company adopted a full yield curve approach for calculating the interest cost component whereby the discount rate for each year is applied to the liability for that specific year. As a result, the interest cost component of net periodic pension and other postretirement benefit plan expense decreased by approximately $7 million in 2016.

A 25 basis point change in any significant assumption (discount rate, salaries, or long-term return on plan assets) would result in a $2 million or less change in total annual benefit expense and a $42 million or less change in projected obligations.

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

Contingent Obligations

The Company is subject to a number of federal and state laws and regulations as well as other factors and conditions that subject it to environmental, litigation, and other risks. See FUTURE EARNINGS POTENTIAL herein and Note 3 to the financial statements for more information regarding certain of these contingencies. The Company periodically evaluates its exposure to such risks and records reserves for those matters where a non-tax-related loss is considered probable and reasonably estimable. The adequacy of reserves can be significantly affected by external events or conditions that can be unpredictable; thus, the ultimate outcome of such matters could materially affect the Company's results of operations, cash flows, or financial condition.

Recently Issued Accounting Standards

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 the Company's revenue, including energy provided to customers, is from tariff offerings that provide natural gas without a defined contractual term, as well as longer-term contractual agreements, including non-derivative natural gas asset management and optimization arrangements.

The 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 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 the Company's financial statements. The 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. The Company applied the modified retrospective method of adoption effective January 1, 2018. The 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.

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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. ASU 2016-02 is effective for fiscal years beginning after December 15, 2018 and the Company will adopt the new standard effective January 1, 2019.

The 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, the 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 real estate and fleet vehicles where the Company is the lessee and to natural gas home appliances where the Company is the lessor. While the Company has not yet determined the ultimate impact, adoption of ASU 2016-02 is expected to have a significant impact on the 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. The 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. The 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 the 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. The 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. The Company adopted ASU 2017-12 effective January 1, 2018 with no material impact on its financial statements.

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FINANCIAL CONDITION AND LIQUIDITY

Overview

The Company's financial condition remained stable at December 31, 2017. The Company's cash requirements primarily consist of funding ongoing operations, common stock dividends, capital expenditures, and debt maturities. Capital expenditures and other investing activities include investments to meet projected long-term demand requirements, to maintain existing natural gas distribution systems as well as to update and expand these systems, and to comply with environmental regulations. Operating cash flows provide a substantial portion of the Company's cash needs. For the three-year period from 2018 through 2020, the Company's projected common stock dividends, capital expenditures, and debt maturities are expected to exceed operating cash flows. The Company plans to finance future cash needs in excess of its operating cash flows primarily through external securities issuances, equity contributions from Southern Company, and borrowings from financial institutions and with proceeds from the pending asset sales of Elizabethtown Gas and Elkton Gas. The Company plans to use commercial paper to manage seasonal variations in operating cash flows and other working capital needs. The Company intends to continue to monitor its access to short-term and long-term capital markets as well as its bank credit arrangements to meet future capital and liquidity needs. See "Sources of Capital," "Financing Activities," and "Capital Requirements and Contractual Obligations" herein for additional information.

By regulation, Nicor Gas is restricted, to the extent of its retained earnings balance, in the amount it can dividend or loan to affiliates and is not permitted to make money pool loans to affiliates. The New Jersey BPU restricts the amount Elizabethtown Gas can dividend to its parent company to 70% of its quarterly net income. Additionally, as stipulated in the New Jersey BPU's order approving the Merger, the Company is prohibited from paying dividends to its parent company, Southern Company, if the Company's senior unsecured debt rating falls below investment grade. At December 31, 2017, the amount of subsidiary retained earnings and net income restricted to dividend totaled $719 million. These restrictions did not have any impact on the Company's ability to meet its cash obligations, nor does management expect such restrictions to materially impact the Company's ability to meet its currently anticipated cash obligations.

The Company's investments in the qualified pension plan increased in value at December 31, 2017 as compared to December 31, 2016. There were no voluntary contributions to the qualified pension plan in 2017 and no mandatory contributions to its qualified pension plan are anticipated during 2018. See Note 2 to the financial statements for additional information.

Net cash provided from operating activities totaled $883 million for 2017, primarily due to earnings and the timing of cash receipts for the sale of natural gas inventory and vendor payments. Net cash used for operating activities was $328 million for the successor period of July 1, 2016 through December 31, 2016, primarily due to a $125 million voluntary pension contribution, a $35 million payment for the settlement of an interest rate swap, and less cash due to the timing of collecting receivables and disbursing payables. Due to the seasonal nature of its business, the Company typically reports negative cash flows from operating activities in the second half of the year. Net cash provided from operating activities was $1.1 billion for the predecessor period of January 1, 2016 through June 30, 2016, primarily due to low volumes of natural gas sales and changes in natural gas inventory as a result of warmer weather and the timing of recovery of related gas costs and weather normalization adjustments from customers. Net cash provided from operating activities was $1.4 billion for the predecessor year ended December 31, 2015, primarily due to the timing of recovery of related gas costs from customers, cash provided from derivative financial instrument assets and liabilities, and a tax refund of $150 million related to the extension of bonus depreciation.

Net cash used for investing activities totaled $1.6 billion for 2017, which reflected $1.5 billion in capital expenditures primarily due to gross property additions for infrastructure replacement programs at gas distribution operations and $145 million in capital contributions to equity method investments in pipeline projects, partially offset by $80 million in returned capital from equity method investments in pipeline projects. Net cash used for investing activities was $2.1

billion for the successor period of July 1, 2016 through December 31, 2016, which reflected $1.4 billion primarily related to the Company's acquisition of the 50% interest in SNG, and $632 million in capital expenditures. Net cash used for investing activities was $559 million and $1.0 billion for the predecessor period of January 1, 2016 through June 30, 2016 and the predecessor year ended December 31, 2015, respectively, which primarily related to capital expenditures. See Note 4 to the financial statements under "Equity Method Investments – SNG" and Note 11 to the financial statements under "Investment in SNG" for additional information.

Net cash provided from financing activities totaled $741 million for 2017, primarily due to $850 million in debt issuances, $262 million in net additional commercial paper borrowings, and $103 million in capital contributions from Southern Company, partially offset by $443 million in common stock dividend payments to Southern Company and $22 million in repayment of long-term debt. Net cash provided from financing activities was $2.4 billion for the successor period of July 1, 2016 through December 31, 2016, which reflected $1.1 billion of capital contributions from Southern Company, primarily used to fund the

Company's investment in SNG, $1.1 billion in net additional commercial paper borrowings, partially offset by $160 million for the purchase of the 15% noncontrolling ownership interest in SouthStar, and $900 million in proceeds from debt issuances, partially offset by $420 million in debt payments. Net cash used for financing activities was $558 million for the predecessor period of January 1, 2016 through June 30, 2016, primarily due to $896 million in net repayment of commercial paper borrowings and $125 million in repayment of long-term debt, partially offset by $600 million in debt issuances. Net cash used for financing activities was $366 million for the predecessor year ended December 31, 2015, primarily due to the net repayment of commercial paper borrowings, partially offset by the proceeds from debt issuances in excess of debt repayments. See Note 4 to the financial statements under "Variable Interest Entities" and "Equity Method Investments – SNG" and Note 11 to the financial statements under "Investment in SNG" for additional information.

Significant balance sheet changes at December 31, 2017 include an increase of $1.2 billion in total property, plant, and equipment primarily due to capital expenditures for infrastructure replacement programs, an increase of $1.0 billion in deferred credits related to income taxes primarily resulting from the impacts of the Tax Reform Legislation, a decrease of $886 million in accumulated deferred income tax liabilities primarily due to the change in the federal corporate income tax rate, partially offset by tax depreciation related to infrastructure assets placed in service as well as the impact of State of Illinois tax legislation, and an increase in long-term debt of $632 million, primarily due to $450 million of senior notes issued in May 2017 and $200 million of first mortgage bonds at Nicor Gas issued in each of August 2017 and November 2017. Other significant balance sheet changes include an increase of $261 million in notes payable primarily related to an increase in commercial paper borrowings of $510 million at Southern Company Gas Capital, partially offset by a decrease in commercial paper borrowings of $249 million at Nicor Gas. See FUTURE EARNINGS POTENTIAL – "Income Tax Matters" and FINANCIAL CONDITION AND LIQUIDITY – "Financing Activities" herein and Notes 5 and 6 to the financial statements for additional information.

Sources of Capital

The Company plans to obtain the funds to meet its future capital needs through operating cash flows, external securities issuances, borrowings from financial institutions, and equity contributions from Southern Company. In addition, the Company plans to utilize the proceeds from the pending asset sales of Elizabethtown Gas and Elkton Gas to pay the income taxes resulting from the sales, to retire existing debt, and for general corporate purposes. However, the amount, type, and timing of any future financings, if needed, depend upon prevailing market conditions, regulatory approval, and other factors. The issuance of securities by Nicor Gas is generally subject to the approval of the Illinois Commission.

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

The Company maintains commercial paper programs at Southern Company Gas Capital and Nicor Gas that consist of short-term, unsecured promissory notes. 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 Company's other subsidiaries benefit from Southern Company Gas Capital's commercial paper program.

At December 31, 2017, the Company's current liabilities exceeded current assets by $1.0 billion, primarily as a result of $1.5 billion in notes payable. The Company's current liabilities frequently exceed current assets because of commercial paper borrowings used to fund daily operations, scheduled maturities of long-term debt, and significant seasonal fluctuations in cash needs. The Company intends to utilize operating cash flows, external securities issuances, borrowings from financial institutions, equity contributions from Southern Company, and the proceeds from the pending asset sales of Elizabethtown Gas and Elkton Gas to fund short-term capital needs. The Company has substantial cash flow from operating activities and access to capital markets and financial institutions to meet liquidity needs.

At December 31, 2017, the Company had $73 million of cash and cash equivalents. Committed credit arrangements with banks at December 31, 2017 were as follows:

| Company | Expires 2022 | Unused |
|---|---|---|
| | (millions) | |
| Southern Company Gas Capital(*) | $1,400 | $1,390 |
| Nicor Gas | 500 | 500 |
| Total | $1,900 | $1,890 |

(*)The Company guarantees the obligations of Southern Company Gas Capital.

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

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 (Facility) currently allocated for $1.4 billion and $500 million, respectively, with a maturity date of 2022, as reflected in the table above. Pursuant to the Facility, the allocations between Southern Company Gas Capital and Nicor Gas may be adjusted.

The Facility contains a covenant that limits the ratio of debt to capitalization (as defined in each facility) to a maximum of 70% for each of the Company and Nicor Gas and contains a cross-acceleration provision to other indebtedness (including guarantee obligations) of the applicable company. Such cross-acceleration provision to other indebtedness would trigger an event of default of the applicable company if the Company or Nicor Gas defaulted on indebtedness, the payment of which was then accelerated. At December 31, 2017, both companies were in compliance with such covenant. The Facility does not contain a material adverse change clause at the time of borrowings.

Subject to applicable market conditions, the applicable company expects to renew or replace the Facility as needed, prior to expiration. In connection therewith, the applicable company may extend the maturity dates and/or increase or decrease the lending commitments thereunder. A portion of unused credit with banks provides liquidity support to the Company.

The Company makes short-term borrowings primarily through commercial paper programs that have the liquidity support of the committed bank credit arrangements described above. Commercial paper 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) |
| Successor – December 31, 2017: | | | | | |
| Southern Company Gas Capital | $1,243 | 1.73 % | $ 723 | 1.40 % | $ 1,243 |
| Nicor Gas | 275 | 1.83 % | 176 | 1.12 % | 525 |
| Total | $1,518 | 1.75 % | $ 899 | 1.35 % | |
| Successor – December 31, 2016: | | | | | |
| Southern Company Gas Capital | $733 | 1.09 % | $ 461 | 0.79 % | $ 770 |
| Nicor Gas | 524 | 0.95 % | 309 | 0.67 % | 587 |
| Total | $1,257 | 1.03 % | $ 770 | 0.74 % | |
| Predecessor – December 31, 2015: | | | | | |
| Southern Company Gas Capital | $471 | 0.71 % | $ 382 | 0.49 % | $ 787 |
| Nicor Gas | 539 | 0.52 % | 349 | 0.38 % | 585 |
| Total | $1,010 | 0.60 % | $ 731 | 0.44 % | |

(*) Average and maximum amounts are based upon daily balances during the 12-month periods.

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

Additionally, 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 totaling $200 million have been issued. 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.

Financing Activities

The long-term debt on the Company's balance sheets includes both principal and non-principal components. As of December 31, 2017, the non-principal components totaled $508 million, including the amount attributable to long-term debt due within one year, which consisted of the unamortized portions of the fair value adjustment recorded in purchase accounting, debt premiums, debt discounts, and debt issuance costs.

In December 2016, the Company executed intercompany promissory notes to further allocate interest expense to its reportable segments that previously remained in the "all other" segment. These intercompany promissory notes allow the Company to calculate net income, which is its performance measure subsequent to the Merger, at the segment level that incorporates the full impact of interest costs.

In May 2017, Southern Company Gas Capital issued $450 million aggregate principal amount of Series 2017A 4.40% Senior Notes due May 30, 2047. The proceeds were used to repay the Company's short-term indebtedness and for general corporate purposes.

In July 2017, Atlanta Gas Light repaid at maturity $22 million of Series C medium-term notes.

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.

On January 4, 2018, the Company issued a floating rate promissory note to Southern Company, in an aggregate principal amount of $100 million due July 31, 2018 bearing interest based on one-month LIBOR, to support the current activities of wholesale gas services.

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

Credit Rating Risk

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

There are certain contracts that could require collateral, but not accelerated payment, in the event of a credit rating change below BBB- and/or Baa3. These contracts are for physical gas purchases and sales and energy price risk management. The maximum potential collateral requirement under these contracts at December 31, 2017 was $10 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 the Company to access capital markets and would be likely to impact the cost at which it does so.

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

While it is unclear how the credit rating agencies and the 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, including the Company, may be negatively impacted. Absent actions by Southern Company and its subsidiaries, including the Company, to mitigate the resulting impacts, which, among other alternatives, could include adjusting capital structure and/or monetizing regulatory assets, the Company's, Southern Company Gas Capital's, and Nicor Gas' credit ratings could be negatively affected. See Note 3 to the financial statements for additional information.

Market Price Risk

The Company is exposed to market risks, primarily commodity price risk, interest rate risk, and weather risk. Due to various cost recovery mechanisms, the natural gas distribution utilities of the Company that sell natural gas directly to end-use customers have limited exposure to market volatility of natural gas prices. To manage the volatility attributable to these exposures, the Company nets the exposures, where possible, to take advantage of natural offsets and enters into various derivative transactions for the remaining exposures pursuant to the Company's policies in areas such as counterparty exposure and risk management practices. The Company uses derivatives to buy and sell natural gas as well as 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.



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To mitigate future exposure to changes in interest rates, the Company may enter into derivatives designated as hedges. The weighted average interest rate on $200 million of long-term variable interest rate exposure at December 31, 2017 was 1.71%. If the Company sustained a 100 basis point change in interest rates for all long-term variable interest rate exposure, the change would have an immaterial effect on annualized interest expense at December 31, 2017. See Note 1 to the financial statements under "Financial Instruments" and Note 10 to the financial statements for additional information.

Certain natural gas distribution utilities of the Company manage fuel-hedging programs implemented per the guidelines of their respective state regulatory agencies to hedge the impact of market fluctuations in natural gas prices for customers. For the weather risk associated with Nicor Gas, the Company has a corporate weather hedging program that utilizes weather derivatives to reduce the risk of lower adjusted operating margins potentially resulting from significantly warmer-than-normal weather. In addition, certain non-regulated operations routinely utilize various types of derivative instruments to economically hedge certain commodity price and weather risks inherent in the natural gas industry. These instruments include a variety of exchange-traded and over-the-counter (OTC) energy contracts, such as forward contracts, futures contracts, options contracts, and swap agreements. Gas marketing services and wholesale gas services also actively manage storage positions through a variety of hedging transactions for the purpose of managing exposures arising from changing natural gas prices. These hedging instruments are used to substantially protect economic margins (as spreads between wholesale and retail natural gas prices widen between periods) and thereby minimize exposure to declining operating margins. Some of these economic hedge activities may not qualify, or are not designated, for hedge accounting treatment. The 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.

For the periods presented below, the changes in net fair value of derivative contracts were as follows:

| | Successor | | Predecessor | |
|---|---|---|---|---|
| | Year Ended December 31, 2017 | July 1, 2016 through December 31, 2016 | January 1, 2016 through June 30, 2016 | Year Ended December 31, 2015 |
| | (in millions) | | (in millions) | |
| Contracts outstanding at beginning of period, assets (liabilities), net | $8 | $ (54) | $75 | $ 61 |
| Contracts realized or otherwise settled | (1) | 18 | (77) | (17) |
| Current period changes[(a)] | (113) | 48 | (82) | 32 |
| Contracts outstanding at end of period, assets (liabilities), net | (106) | 12 | (84) | 76 |
| Netting of cash collateral | 193 | 62 | 120 | 96 |
| Cash collateral and net fair value of contracts outstanding at end of period[(b)] | $87 | $ 74 | $36 | $ 172 |

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

(b) Net fair value of derivative contracts outstanding 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, $5 million at June 30, 2016, and $10 million at December 31, 2015.

The net hedge volume of energy-related derivative contracts for natural gas positions for the years ended December 31 were as follows:

2017 2016

| | mmBtu Volume (in millions) | |
|---|---|---|
| Commodity – Natural gas | 300 | 157 |
| Net Purchased/(Sold) Volume | 300 | 157 |

The Company's derivative contracts are comprised of both long and short natural gas positions. A long position is a contract to purchase natural gas, and a short position is a contract to sell natural gas. The volume presented above represents the net of long natural gas positions of 3.51 billion mmBtu and short natural gas positions of 3.21 billion mmBtu at December 31, 2017 and the net of long natural gas positions of 3.31 billion mmBtu and short natural gas positions of 3.16 billion mmBtu at December 31, 2016.

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Energy-related derivative contracts that are designated as regulatory hedges relate primarily to the Company's fuel-hedging programs. Therefore, gains and losses are initially recorded as regulatory liabilities and assets, respectively, and then are included in cost of natural gas as the underlying gas is used in operations and ultimately recovered through the respective cost recovery clause. Certain other 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 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.

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 natural gas industry. When an energy-related derivative contract is settled physically, any cumulative unrealized gain or loss is reversed and the contract price is recognized in the respective line item representing the actual price of the underlying goods being delivered.

The Company uses OTC contracts that are not exchange traded but are fair valued using prices which are market observable, and thus fall into Level 2 of the fair value hierarchy. See Note 9 to the financial statements for further discussion of fair value measurements.

The maturities of the energy-related derivative contracts at December 31, 2017 were as follows:

| | Fair Value Measurements December 31, 2017 | | | |
|---|---|---|---|---|
| | | Maturity | | |
| | Total Fair Value | Year 1 | Years 2 & 3 | Years 4 & 5 |
| | (in millions) | | | |
| Level 1[(a)] | $(148) | $ (71 ) | $ (59 ) | $ (18 ) |
| Level 2[(b)] | 42 | 10 | 30 | 2 |
| Fair value of contracts outstanding at end of period[(c)] | $(106) | $ (61 ) | $ (29 ) | $ (16 ) |

(a) Valued using NYMEX futures prices.

(b) Valued using basis transactions that represent the cost to transport natural gas from a NYMEX delivery point to the contract delivery point. These transactions are based on quotes obtained either through electronic trading platforms or directly from brokers.

(c) Excludes cash collateral of $193 million as well as premium and associated intrinsic value associated with weather derivatives of $11 million at December 31, 2017.

Value at Risk (VaR)

VaR is the maximum potential loss in portfolio value over a specified time period that is not expected to be exceeded within a given degree of probability. The Company's VaR may not be comparable to that of other companies due to differences in the factors used to calculate VaR. The Company's VaR is determined on a 95% confidence interval and a one-day holding period, which means that 95% of the time, the risk of loss in a day from a portfolio of positions is expected to be less than or equal to the amount of VaR calculated. The open exposure of the Company is managed in accordance with established policies that limit market risk and require daily reporting of potential financial exposure to senior management. Because the Company generally manages physical gas assets and economically protects its positions by hedging in the futures markets, the Company's open exposure is generally mitigated. The Company employs daily risk testing, using both VaR and stress testing, to evaluate the risk of its positions.

The Company actively monitors open commodity positions and the resulting VaR and maintains a relatively small risk exposure as total buy volume is close to sell volume, with minimal open natural gas price risk. Based on a 95% confidence interval and employing a one-day holding period, SouthStar's portfolio of positions for all periods presented was immaterial.

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For the periods presented below, wholesale gas services had the following VaRs:

| | Successor | | Predecessor | |
|---|---|---|---|---|
| | Year Ended December 31, 2017 | July 1, 2016 through December 31, 2016 | January 1, 2016 through June 30, 2016 | Year Ended December 31, 2015 |
| | (in millions) | | (in millions) | |
| Period end(*) | $ 4.8 | $ 2.3 | $ 1.9 | $ 2.4 |
| Average | 2.0 | 2.0 | 2.0 | 3.0 |
| High(*) | 4.8 | 2.8 | 2.5 | 7.3 |
| Low | 1.0 | 1.4 | 1.6 | 1.6 |

(*) Increase in VaR at December 31, 2017 was driven by significant natural gas price increases in Sequent's key markets due to colder-than-normal weather. As weather moderated during January 2018, VaR reduced to a level consistent with prior periods.

Credit Risk

Gas Distribution Operations

Concentration of credit risk occurs at Atlanta Gas Light for amounts billed for services and other costs to its customers, which consist of 15 Marketers in Georgia. The credit risk exposure to Marketers varies seasonally, with the lowest exposure in the non-peak summer months and the highest exposure in the peak winter months. Marketers are responsible for the retail sale of natural gas to end-use customers in Georgia. The functions of the retail sale of gas include the purchase and sale of natural gas, customer service, billings, and collections. The provisions of Atlanta Gas Light's tariff allow Atlanta Gas Light to obtain credit security support in an amount equal to a minimum of two times a Marketer's highest month's estimated bill from Atlanta Gas Light. For 2017, the four largest Marketers based on customer count accounted for 19% of the Company's adjusted operating margin and 22% of gas distribution operations' adjusted operating margin.

Several factors are designed to mitigate the Company's risks from the increased concentration of credit that has resulted from deregulation. In addition to the security support described above, Atlanta Gas Light bills intrastate delivery service to Marketers in advance rather than in arrears. Atlanta Gas Light accepts credit support in the form of cash deposits, letters of credit/surety bonds from acceptable issuers, and corporate guarantees from investment-grade entities. On a monthly basis, the Risk Management Committee reviews the adequacy of credit support coverage, credit rating profiles of credit support providers, and payment status of each Marketer. The Company believes that adequate policies and procedures are in place to properly quantify, manage, and report on Atlanta Gas Light's credit risk exposure to Marketers.

Atlanta Gas Light also faces potential credit risk in connection with assignments of interstate pipeline transportation and storage capacity to Marketers. Although Atlanta Gas Light assigns this capacity to Marketers, in the event that a Marketer fails to pay the interstate pipelines for the capacity, the interstate pipelines would likely seek repayment from Atlanta Gas Light.

Gas Marketing Services

The Company obtains credit scores for its firm residential and small commercial customers using a national credit reporting agency, enrolling only those customers that meet or exceed the Company's credit threshold. The Company considers potential interruptible and large commercial customers based on reviews of publicly available financial statements and commercially available credit reports. Prior to entering into a physical transaction, the Company also assigns physical wholesale counterparties an internal credit rating and credit limit based on the counterparties' Moody's, S&P, and Fitch ratings, commercially available credit reports, and audited financial statements.

Wholesale Gas Services

The Company has established credit policies to determine and monitor the creditworthiness of counterparties, as well as the quality of pledged collateral. The Company also utilizes master netting agreements whenever possible to mitigate exposure to counterparty credit risk. When the Company is engaged in more than one outstanding derivative transaction with the same counterparty and 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 the Company's credit risk. The Company also uses other netting agreements with certain counterparties with whom it conducts significant transactions. Master netting agreements enable the Company to net certain assets and liabilities by counterparty. The Company also nets across product lines and against cash collateral, provided the master netting and cash collateral agreements include such provisions.

The Company may require counterparties to pledge additional collateral when deemed necessary. The Company conducts credit evaluations and obtains appropriate internal approvals for a 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, the Company requires credit enhancements by way of a guaranty, cash deposit, or letter of credit for transaction counterparties that do not have investment grade ratings.

Certain of the Company's derivative instruments contain credit-risk-related or other contingent features that could increase the payments for collateral it posts in the normal course of business when its financial instruments are in net liability positions. At December 31, 2017, for agreements with such features, the Company's derivative instruments with liability fair values totaled $1 million for which the Company had no collateral posted with derivatives counterparties to satisfy these arrangements.

The Company has a concentration of credit risk as measured by its 30-day receivable exposure plus forward exposure. At December 31, 2017, wholesale gas services' 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. The S&P equivalent credit rating is determined by a process of converting the lower of the S&P or Moody's ratings to an internal rating ranging from 9 to 1, with 9 being equivalent to AAA/Aaa by S&P and Moody's, respectively, and 1 being D / Default by S&P and Moody's, respectively. A counterparty that does not have an external rating is assigned an internal rating based on the strength of the financial ratios of that counterparty. To arrive at the weighted average credit rating, each counterparty is assigned an internal ratio, which is multiplied by their credit exposure and summed for all counterparties. The sum is divided by the aggregate total counterparties' exposures, and this numeric value is then converted to an S&P equivalent.

The following table provides credit risk information related to the Company's third-party natural gas contracts receivable and payable positions at December 31:

| | Gross Receivables | | Gross Payables | |
|---|---|---|---|---|
| | 2017 | 2016 | 2017 | 2016 |
| | (in millions) | | (in millions) | |
| Netting agreements in place: | | | | |
| Counterparty is investment grade | $342 | $375 | $202 | $227 |
| Counterparty is non-investment grade | 20 | 14 | 25 | 31 |
| Counterparty has no external rating | 226 | 223 | 315 | 339 |
| No netting agreements in place: | | | | |
| Counterparty is investment grade | 19 | 11 | 4 | — |
| Amount recorded in balance sheets | $607 | $623 | $546 | $597 |

Capital Requirements and Contractual Obligations

The Company's capital investments are currently estimated to total $1.7 billion for 2018, $1.7 billion for 2019, $1.5 billion for 2020, $1.2 billion for 2021, and $1.4 billion for 2022. The Company's capital investments include estimated capital expenditures related to Elizabethtown Gas and Elkton Gas of $123 million for 2018, $125 million for 2019, $124 million for 2020, $126 million for 2021, and $129 million for 2022. See Note 11 to the financial statements under "Proposed Sale of Elizabethtown Gas and Elkton Gas" for additional information. The regulatory infrastructure programs and other construction programs are subject to periodic review and revision, and actual costs may vary from these estimates because of numerous factors. These factors include: changes in business conditions; changes in FERC rules and regulations; state regulatory agency approvals; changes in legislation; the cost and efficiency of labor, equipment, and materials; project scope and design changes; and the cost of capital. In addition, there can be no assurance that costs related to capital expenditures will be fully recovered.

In addition, as discussed in Note 2 to the financial statements, the Company provides postretirement benefits to certain eligible employees and funds trusts to the extent required by the applicable state regulatory agencies.

Other funding requirements related to obligations associated with scheduled maturities of long-term debt, including the related interest; pipeline charges, storage capacity, and gas supply; operating leases; asset management agreements; financial derivative obligations; pension and other postretirement benefit plans; and other purchase commitments, primarily related to environmental remediation liabilities, are detailed in the contractual obligations table that follows. See Notes 3, 6, 7, and 11 to the financial statements for additional information.

MANAGEMENT'S DISCUSSION AND ANALYSIS (continued)
Southern Company Gas and Subsidiary Companies 2017 Annual Report

Contractual Obligations
Contractual obligations at December 31, 2017 were as follows:

| | 2018 | 2019-2020 | 2021-2022 | After 2022 | Total |
|---|---|---|---|---|---|
| | (in millions) | | | | |
| Long-term debt[(a)] — | | | | | |
| Principal | $155 | $350 | $423 | $4,612 | $5,540 |
| Interest | 241 | 452 | 421 | 3,137 | 4,251 |
| Pipeline charges, storage capacity, and gas supply[(b)] | 813 | 968 | 714 | 2,294 | 4,789 |
| Operating leases[(c)] | 17 | 32 | 28 | 26 | 103 |
| Asset management agreements[(d)] | 9 | 6 | — | — | 15 |
| Financial derivative obligations[(e)] | 444 | 174 | 37 | 5 | 660 |
| Pension and other postretirement benefit plans[(f)] | 13 | 28 | — | — | 41 |
| Purchase commitments — | | | | | |
| Capital[(g)] | 1,821 | 2,979 | 2,662 | — | 7,462 |
| Other[(h)] | 31 | 7 | 2 | 1 | 41 |
| Total | $3,544 | $4,996 | $4,287 | $10,075 | $22,902 |

(a) Amounts are reflected based on final maturity dates. The Company plans to continue, when economically feasible, to retire higher-cost securities and replace these obligations with lower-cost capital if market conditions permit. Variable rate interest obligations are estimated based on rates at December 31, 2017, as reflected in the statements of capitalization.

(b) Includes charges recoverable through a natural gas cost recovery mechanism, or alternatively billed to Marketers, and demand charges associated with Sequent. The gas supply balance includes amounts for Nicor Gas and SouthStar gas commodity purchase commitments of 35 million mmBtu at floating gas prices calculated using forward natural gas prices at December 31, 2017 and valued at $101 million. The Company provides guarantees to certain gas suppliers for certain of its subsidiaries, including SouthStar, in support of payment obligations.

(c) Certain operating leases have provisions for step rent or escalation payments and certain lease concessions are accounted for by recognizing the future minimum lease payments on a straight-line basis over the respective minimum lease terms. However, this accounting treatment does not affect the future annual operating lease cash obligations as shown herein. In terms of rental charges and duration of contracts, the Company's most significant operating leases relate to real estate.

(d) Represent fixed-fee minimum payments for Sequent's affiliated asset management agreements.

(e) See Notes 1 and 10 to the financial statements for additional information.

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

(g) Estimated capital expenditures are provided through 2022. Capital includes amounts related to Elizabethtown Gas and Elkton Gas, which represent $123 million in 2018, $249 million in 2019-2020, and $255 million in 2021-2022. See Note 11 to the financial statements under "Proposed Sale of Elizabethtown Gas and Elkton Gas" for additional information. Capital also includes amounts related to the Company's pipeline investments that will be recorded at the joint venture level, which represent $64 million in 2018, $195 million in 2019-2020, and less than $1 million in capital expenditures in 2021-2022.

(h) Includes contractual environmental remediation liabilities that are generally recoverable through base rates or rate rider mechanisms and long-term service agreements.

MANAGEMENT'S DISCUSSION AND ANALYSIS (continued)
Southern Company Gas and Subsidiary Companies 2017 Annual Report

Cautionary Statement Regarding Forward-Looking Statements

The Company's 2017 Annual Report contains forward-looking statements. Forward-looking statements include, among other things, statements concerning regulatory matters, the strategic goals for the Company, economic conditions, natural gas price volatility, derivative losses, regulatory and environmental cost recovery and other rate actions, current and proposed environmental regulations and related compliance plans and estimated expenditures, pending or potential litigation matters, access to sources of capital, projections for the qualified pension plan 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, and estimated 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 Company is 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 Company, Southern Company Gas Capital, and Nicor Gas;
- 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 Company operates;
- variations in demand for 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, and any potential economic impacts resulting from federal fiscal decisions;
- available sources and costs of natural gas;
- limits on pipeline capacity;
- effects of inflation;
- the ability to control costs and avoid cost overruns during the development and construction of facilities;
- investment performance of the Company's employee and retiree benefit plans;
- advances in technology;
- state and federal rate regulations and the impact of pending and future rate cases and negotiations, including rate actions relating to natural gas and other cost recovery mechanisms;
- the inherent risks involved in transporting and storing natural gas;
- the ability to successfully operate the natural gas distribution and storage facilities and the successful performance of necessary corporate functions;
- internal restructuring or other restructuring options that may be pursued;
- potential business strategies, including acquisitions or dispositions of assets or businesses, including the proposed disposition of Elizabethtown Gas and Elkton Gas, which cannot be assured to be completed or beneficial to the Company;
- 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 integration with Southern Company will be greater than expected;
- the ability of counterparties of the Company to make payments as and when due and to perform as required;
- the direct or indirect effect on the Company'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 Company's, Southern Company Gas Capital's, and Nicor Gas' 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;

- catastrophic events such as fires, earthquakes, explosions, floods, tornadoes, hurricanes and other storms, droughts, pandemic health events such as influenzas, or other similar occurrences;
- the direct or indirect effects on the Company's business resulting from incidents affecting the U.S. natural gas pipeline infrastructure or operation of 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 filed by the Company from time to time with the SEC.

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

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CONSOLIDATED STATEMENTS OF INCOME
Southern Company Gas and Subsidiary Companies 2017 Annual Report

| | Successor | | Predecessor | |
|---|---|---|---|---|
| | For the year ended December 31, 2017 | July 1, 2016 through December 31, 2016 | January 1, 2016 through June 30, 2016 | For the year ended December 31, 2015 |
| | (in millions) | | (in millions) | |
| Operating Revenues: | | | | |
| Natural gas revenues (includes revenue taxes of $100, $32, $57, and $103 for the periods presented, respectively) | $3,791 | $ 1,596 | $1,841 | $ 3,817 |
| Other revenues | 129 | 56 | 64 | 124 |
| Total operating revenues | 3,920 | 1,652 | 1,905 | 3,941 |
| Operating Expenses: | | | | |
| Cost of natural gas | 1,601 | 613 | 755 | 1,617 |
| Cost of other sales | 29 | 10 | 14 | 28 |
| Other operations and maintenance | 940 | 482 | 454 | 928 |
| Depreciation and amortization | 501 | 238 | 206 | 397 |
| Taxes other than income taxes | 184 | 71 | 99 | 181 |
| Merger-related expenses | — | 41 | 56 | 44 |
| Total operating expenses | 3,255 | 1,455 | 1,584 | 3,195 |
| Operating Income | 665 | 197 | 321 | 746 |
| Other Income and (Expense): | | | | |
| Earnings from equity method investments | 106 | 60 | 2 | 6 |
| Interest expense, net of amounts capitalized | (200) | (81) | (96) | (175) |
| Other income (expense), net | 39 | 14 | 5 | 9 |
| Total other income and (expense) | (55) | (7) | (89) | (160) |
| Earnings Before Income Taxes | 610 | 190 | 232 | 586 |
| Income taxes | 367 | 76 | 87 | 213 |
| Net Income | 243 | 114 | 145 | 373 |
| Less: Net income attributable to noncontrolling interest | — | — | 14 | 20 |
| Net Income Attributable to Southern Company Gas | $243 | $ 114 | $131 | $ 353 |

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

CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME
Southern Company Gas and Subsidiary Companies 2017 Annual Report

| | Successor | | Predecessor | |
|---|---|---|---|---|
| | For the year ended December 31, 2017 | July 1, 2016 through December 31, 2016 | January 1, 2016 through June 30, 2016 | For the year ended December 31, 2015 |
| | (in millions) | | (in millions) | |
| Net Income | $243 | $ 114 | $145 | $ 373 |
| Other comprehensive income (loss): | | | | |
| Qualifying hedges: | | | | |
| Changes in fair value, net of tax of $(3), $(1), $(23), and $(3), respectively | (5) | (1) | (41) | — |
| Reclassification adjustment for amounts included in net income, net of tax of $-, $-, $-, and $1, respectively | 1 | — | 1 | 8 |
| Pension and other postretirement benefit plans: | | | | |
| Benefit plan net gain (loss), net of tax of $-, $19, $-, and $-, respectively | (1) | 27 | — | — |
| Reclassification adjustment for amounts included in net income, net of tax of $-, $-, $4, and $9, respectively | — | — | 5 | 12 |
| Total other comprehensive income (loss) | (5) | 26 | (35) | 20 |
| Less: Comprehensive income attributable to noncontrolling interest | — | — | 14 | 20 |
| Comprehensive Income Attributable to Southern Company Gas | $238 | $ 140 | $96 | $ 373 |

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

CONSOLIDATED STATEMENTS OF CASH FLOWS
Southern Company Gas and Subsidiary Companies 2017 Annual Report

| | Successor | | Predecessor | |
|---|---|---|---|---|
| | For the year ended December 31, 2017 | July 1, 2016 through December 31, 2016 | January 1, 2016 through June 30, 2016 | For the year ended December 31, 2015 |
| | (in millions) | | (in millions) | |
| Operating Activities: | | | | |
| Net income | $243 | $ 114 | $145 | $ 373 |
| Adjustments to reconcile net income to net cash provided from (used for) operating activities — | | | | |
| Depreciation and amortization, total | 501 | 238 | 206 | 397 |
| Deferred income taxes | 236 | 92 | 8 | 211 |
| Pension, postretirement, and other employee benefits | (1) | 6 | 5 | 24 |
| Pension and postretirement funding | — | (125) | — | — |
| Stock based compensation expense | 32 | 20 | 20 | 34 |
| Hedge settlements | — | (35) | (26) | — |
| Goodwill impairment | — | — | — | 14 |
| Mark-to-market adjustments | (24) | (3) | 162 | 22 |
| Other, net | (83) | (78) | (82) | 43 |
| Changes in certain current assets and liabilities — | | | | |
| -Receivables | (91) | (490) | 181 | 615 |
| -Natural gas for sale, net of temporary LIFO liquidation | 36 | (226) | 273 | 72 |
| -Prepaid income taxes | (39) | (23) | 151 | 23 |
| -Other current assets | (24) | (31) | 37 | (11) |
| -Accounts payable | (20) | 194 | 43 | (434) |
| -Accrued taxes | 110 | 8 | 41 | (20) |
| -Accrued compensation | 15 | (13) | (21) | (6) |
| -Other current liabilities | (8) | 24 | (30) | 24 |
| Net cash provided from (used for) operating activities | 883 | (328) | 1,113 | 1,381 |
| Investing Activities: | | | | |
| Property additions | (1,514) | (614) | (509) | (961) |
| Cost of removal, net of salvage | (66) | (40) | (32) | (84) |
| Change in construction payables, net | 72 | 22 | (7) | 18 |
| Investment in unconsolidated subsidiaries | (145) | (1,444) | (14) | (12) |
| Returned investment in unconsolidated subsidiaries | 80 | 5 | 3 | 12 |
| Other investing activities | 3 | 4 | — | — |
| Net cash used for investing activities | (1,570) | (2,067) | (559) | (1,027) |
| Financing Activities: | | | | |
| Increase (decrease) in notes payable, net | 262 | 1,143 | (896) | (165) |
| Proceeds — | | | | |
| First mortgage bonds | 400 | — | 250 | — |
| Capital contributions from parent company | 103 | 1,085 | — | — |
| Senior notes | 450 | 900 | 350 | 250 |

| | | | | |
|---|---|---|---|---|
| Redemptions and repurchases — | | | | |
| Medium-term notes | (22 ) | — | — | — |
| First mortgage bonds | — | — | (125 ) | — |
| Senior notes | — | (420 ) | — | (200 ) |
| Distribution to noncontrolling interest | — | (15 ) | (19 ) | (18 ) |
| Purchase of 15% noncontrolling interest in SouthStar | — | (160 ) | — | — |
| Payment of common stock dividends | (443 ) | (126 ) | (128 ) | (244 ) |
| Other financing activities | (9 ) | (8 ) | 10 | 11 |
| Net cash provided from (used for) financing activities | 741 | 2,399 | (558 ) | (366 ) |
| Net Change in Cash and Cash Equivalents | 54 | 4 | (4 ) | (12 ) |
| Cash and Cash Equivalents at Beginning of Period | 19 | 15 | 19 | 31 |
| Cash and Cash Equivalents at End of Period | $73 | $ 19 | $15 | $ 19 |

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

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CONSOLIDATED BALANCE SHEETS
At December 31, 2017 and 2016
Southern Company Gas and Subsidiary Companies 2017 Annual Report

| Assets | 2017 | 2016 |
|---|---|---|
| | (in millions) | |
| Current Assets: | | |
| Cash and cash equivalents | $73 | $19 |
| Receivables — | | |
| Energy marketing receivable | 607 | 623 |
| Customer accounts receivable | 400 | 364 |
| Unbilled revenues | 285 | 239 |
| Other accounts and notes receivable | 103 | 76 |
| Accumulated provision for uncollectible accounts | (28) | (27) |
| Materials and supplies | 24 | 26 |
| Natural gas for sale | 595 | 631 |
| Prepaid income taxes | 26 | 24 |
| Prepaid expenses | 53 | 55 |
| Assets from risk management activities, net of collateral | 135 | 128 |
| Other regulatory assets, current | 94 | 81 |
| Other current assets | 28 | 11 |
| Total current assets | 2,395 | 2,250 |
| Property, Plant, and Equipment: | | |
| In service | 15,833 | 14,508 |
| Less: Accumulated depreciation | 4,596 | 4,439 |
| Plant in service, net of depreciation | 11,237 | 10,069 |
| Construction work in progress | 491 | 496 |
| Total property, plant, and equipment | 11,728 | 10,565 |
| Other Property and Investments: | | |
| Goodwill | 5,967 | 5,967 |
| Equity investments in unconsolidated subsidiaries | 1,477 | 1,541 |
| Other intangible assets, net of amortization of $120 and $34 at December 31, 2017 and December 31, 2016, respectively | 280 | 366 |
| Miscellaneous property and investments | 21 | 21 |
| Total other property and investments | 7,745 | 7,895 |
| Deferred Charges and Other Assets: | | |
| Other regulatory assets, deferred | 901 | 973 |
| Other deferred charges and assets | 218 | 170 |
| Total deferred charges and other assets | 1,119 | 1,143 |
| Total Assets | $22,987 | $21,853 |

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

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CONSOLIDATED BALANCE SHEETS
At December 31, 2017 and 2016
Southern Company Gas and Subsidiary Companies 2017 Annual Report

| Liabilities and Stockholder's Equity | 2017 | 2016 |
|---|---|---|
| | (in millions) | |
| Current Liabilities: | | |
| Securities due within one year | $157 | $22 |
| Notes payable | 1,518 | 1,257 |
| Energy marketing trade payables | 546 | 597 |
| Accounts payable | 446 | 348 |
| Customer deposits | 128 | 153 |
| Accrued taxes — | | |
| Accrued income taxes | 40 | 26 |
| Other accrued taxes | 78 | 68 |
| Accrued interest | 51 | 48 |
| Accrued compensation | 74 | 58 |
| Liabilities from risk management activities, net of collateral | 69 | 62 |
| Other regulatory liabilities, current | 135 | 102 |
| Accrued environmental remediation, current | 46 | 69 |
| Other current liabilities | 113 | 108 |
| Total current liabilities | 3,401 | 2,918 |
| Long-term Debt (See accompanying statements) | 5,891 | 5,259 |
| Deferred Credits and Other Liabilities: | | |
| Accumulated deferred income taxes | 1,089 | 1,975 |
| Deferred credits related to income taxes | 1,063 | 22 |
| Employee benefit obligations | 415 | 441 |
| Other cost of removal obligations | 1,646 | 1,616 |
| Accrued environmental remediation, deferred | 342 | 357 |
| Other regulatory liabilities, deferred | 30 | 29 |
| Other deferred credits and liabilities | 88 | 127 |
| Total deferred credits and other liabilities | 4,673 | 4,567 |
| Total Liabilities | 13,965 | 12,744 |
| Common Stockholder's Equity (See accompanying statements) | 9,022 | 9,109 |
| Total Liabilities and Stockholder's Equity | $22,987 | $21,853 |
| Commitments and Contingent Matters (See notes) | | |

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

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CONSOLIDATED STATEMENTS OF CAPITALIZATION
At December 31, 2017 and 2016
Southern Company Gas and Subsidiary Companies 2017 Annual Report

| | 2017 | 2016 | 2017 | 2016 |
|---|---|---|---|---|
| | (in millions) | | (percent of total) | |
| Long-Term Debt: | | | | |
| Long-term notes payable — | | | | |
| 7.20% due 2017 | $— | $22 | | |
| 3.50% due 2018 | 155 | 155 | | |
| 5.25% due 2019 | 300 | 300 | | |
| 3.50% to 9.10% due 2021 | 330 | 330 | | |
| 8.55% to 8.70% due 2022 | 46 | 46 | | |
| 2.45% to 7.30% due 2023-2047 | 3,484 | 3,034 | | |
| Total long-term notes payable | 4,315 | 3,887 | | |
| Other long-term debt — | | | | |
| First mortgage bonds — | | | | |
| 4.70% due 2019 | 50 | 50 | | |
| 2.66% to 6.58% due 2023-2057 | 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 2024-2033 | 153 | 153 | | |
| Total other long-term debt | 1,225 | 825 | | |
| Unamortized fair value adjustment of long-term debt | 525 | 578 | | |
| Unamortized debt discount | (17) | (9) | | |
| Total long-term debt (annual interest requirement — $241 million) | 6,048 | 5,281 | | |
| Less amount due within one year | 157 | 22 | | |
| Long-term debt excluding amount due within one year | 5,891 | 5,259 | 39.5 % | 36.6 % |
| Common Stockholder's Equity: | | | | |
| Common stock — par value $0.01 per share | | | | |
| Authorized — 100 million shares | | | | |
| Outstanding — 100 shares | | | | |
| Paid-in capital | 9,214 | 9,095 | | |
| Accumulated deficit | (212) | (12) | | |
| Accumulated other comprehensive income | 20 | 26 | | |
| Total common stockholder's equity | 9,022 | 9,109 | 60.5 | 63.4 |
| Total Capitalization | $14,913 | $14,368 | 100.0% | 100.0% |

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

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CONSOLIDATED STATEMENTS OF STOCKHOLDERS' EQUITY
Southern Company Gas and Subsidiary Companies 2017 Annual Report

| | Southern Company Gas Common Stockholders' Equity | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|
| | Number of Common Shares | | Common Stock | | | | | | |
| | Issued | Treasury | Par Value | Paid-In Capital | Treasury | Retained Earnings (Accumulated Deficit) | Accumulated Other Comprehensive Income (Loss) | Noncontrolling Interests | Total |
| | (in thousands) | | (in millions) | | | | | | |
| Predecessor – Balance at December 31, 2014 | 119,647 | 217 | $599 | $2,087 | $ (8) | $ 1,312 | $ (206) | $ 44 | $3,828 |
| Consolidated net income attributable to Southern Company Gas | — | — | — | — | — | 353 | — | — | 353 |
| Other comprehensive income (loss) | — | — | — | — | — | — | 20 | — | 20 |
| Stock issued | 221 | — | 1 | 11 | — | — | — | — | 12 |
| Stock-based compensation | 509 | — | 3 | 1 | — | — | — | — | 4 |
| Cash dividends on common stock | — | — | — | — | — | (244) | — | — | (244) |
| Distribution to noncontrolling interest(*) | — | — | — | — | — | — | — | (18) | (18) |
| Net income attributable to noncontrolling interest (*) | — | — | — | — | — | — | — | 20 | 20 |
| Predecessor – Balance at December 31, 2015 | 120,377 | 217 | 603 | 2,099 | (8) | 1,421 | (186) | 46 | 3,975 |
| Consolidated net income attributable to Southern Company Gas | — | — | — | — | — | 131 | — | — | 131 |
| Other comprehensive income (loss) | — | — | — | — | — | — | (35) | — | (35) |
| Stock issued | 95 | — | — | 6 | — | — | — | — | 6 |
| Stock-based compensation | 270 | — | 2 | 28 | — | — | — | — | 30 |
| Cash dividends on common stock | — | — | — | — | — | (128) | — | — | (128) |
| Reclassification of noncontrolling interest (*) | — | — | — | — | — | — | — | (46) | (46) |
| Predecessor – Balance at June 30, 2016 | 120,742 | 217 | 605 | 2,133 | (8) | 1,424 | (221) | — | 3,933 |
| Successor – Balance at July 1, 2016 | — | — | — | 8,001 | — | — | — | — | 8,001 |
| Consolidated net income | — | — | — | — | — | 114 | — | — | 114 |

| | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|
| attributable to Southern Company Gas | | | | | | | | | |
| Capital contributions from parent company | — | — | — | 1,094 | — | — | — | — | 1,094 |
| Other comprehensive income (loss) | — | — | — | — | — | — | 26 | — | 26 |
| Cash dividends on common stock | — | — | — | — | — | (126) | — | — | (126) |
| Successor – Balance at December 31, 2016 | — | — | — | 9,095 | — | (12) | 26 | — | 9,109 |
| Consolidated net income attributable to Southern Company Gas | — | — | — | — | — | 243 | — | — | 243 |
| Capital contributions from parent company, net | — | — | — | 117 | — | — | — | — | 117 |
| Other comprehensive income (loss) | — | — | | — | — | — | (5) | — | (5) |
| Cash dividends on common stock | — | — | — | — | — | (443) | — | — | (443) |
| Other | — | — | — | 2 | — | — | (1) | — | 1 |
| Successor – Balance at December 31, 2017 | — | — | $— | $9,214 | $ — | $ (212) | $ 20 | $ — | $9,022 |

(*) Associated with SouthStar. See Note 4 to the financial statements for additional information.

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

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1. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

General

On July 1, 2016, Southern Company and Southern Company Gas (together with its subsidiaries, the Company) completed the Merger and Southern Company Gas became a wholly-owned, direct subsidiary of Southern Company. In addition to the Company, Southern Company is the parent company of four traditional electric operating companies, Southern Power, SCS, Southern Linc, Southern Holdings, Southern Nuclear, PowerSecure, Inc., and other direct and indirect subsidiaries. The Company is an energy services holding company whose primary business is the distribution of natural gas across seven states through its seven natural gas distribution utilities. The Company also is involved in several other businesses that are complementary to the distribution of natural gas. The traditional electric operating companies – Alabama Power Company, Georgia Power Company, Gulf Power Company, and Mississippi Power Company – 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. 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. PowerSecure, Inc. is a provider of products and services in the areas of distributed generation, energy efficiency, and utility infrastructure.

The financial statements reflect the Company's investments in its subsidiaries on a consolidated basis. The equity method is used for subsidiaries in which the Company has significant influence but does not control and for VIEs where the Company has an equity investment, but is not the primary beneficiary. Intercompany transactions have been eliminated in consolidation.

The seven natural gas distribution utilities are subject to regulation by the regulatory agencies of each state in which they operate. As such, the Company's financial statements reflect the effects of rate regulation in accordance with GAAP and comply with the accounting policies and practices prescribed by its regulatory commissions. The preparation of financial statements in conformity with GAAP requires the use of estimates, and the actual results may differ from those estimates.

Pursuant to the Merger, Southern Company has pushed down the application of the acquisition method of accounting to the financial statements of the Company such that the assets and liabilities are recorded at their respective fair values, and goodwill has been established for the excess of the purchase price over the fair value of net identifiable assets. Accordingly, the financial statements of the Company for periods before and after July 1, 2016 (acquisition date) reflect different bases of accounting, and the financial positions and results of operations of those periods are not comparable. Throughout the financial statements and notes to the financial statements, periods prior to July 1, 2016 are identified as "predecessor," while periods after the acquisition date are identified as "successor."

Certain predecessor period data presented in the financial statements has been modified or reclassified to conform to the presentation used by the Company's new parent company, Southern Company. Changes to the statements of income include classifying operating revenues as natural gas revenues and other revenues as well as classifying cost of goods sold as cost of natural gas and cost of other sales, and presenting interest expense and AFUDC on a gross basis. Changes to the statements of cash flows include revised financial statement line item descriptions to align with the new balance sheet descriptions and expanded line items within each category of cash flow activity. Changes to the balance sheets include changing certain captions to conform to the presentation of Southern Company.

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 the Company's revenue, including energy provided to customers, is from tariff offerings that provide natural gas without a defined contractual term, as well as longer-term contractual agreements, including non-derivative natural gas asset management and optimization arrangements.

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The 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 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 the Company's financial statements. The 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. The Company applied the modified retrospective method of adoption effective January 1, 2018. The 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. ASU 2016-02 is effective for fiscal years beginning after December 15, 2018 and the Company will adopt the new standard effective January 1, 2019.
The 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, the 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 real estate and fleet vehicles where the Company is the lessee and to natural gas home appliances where the Company is the lessor. While the Company has not yet determined the ultimate impact, adoption of ASU 2016-02 is expected to have a significant impact on the 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, the Company recognized any excess tax benefits and deficiencies related to the exercise and vesting of stock compensation as additional paid-in capital. In addition, the new guidance requires excess tax benefits for share-based payments to be included in net cash provided from operating activities rather than net cash provided from financing activities on the statement of cash flows. The Company elected to adopt the guidance in 2016 and reflect the related adjustments as of January 1, 2016. Prior year's data presented in the financial statements has not been adjusted. The Company also elected to recognize forfeitures as they occur. The new guidance did not have a material impact on the results of operations, financial position, or cash flows of the Company. See Note 5 for the disclosure 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. The 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. The Company adopted ASU 2017-04 effective January 1, 2018 with no impact on its financial statements.

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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 the 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. The 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. The Company adopted ASU 2017-12 effective January 1, 2018 with no material impact on its financial statements.

Affiliate Transactions

SCS, as agent for Alabama Power, Georgia Power, and Southern Power, and the Company have long-term interstate natural gas transportation agreements with SNG. The interstate transportation service provided to Alabama Power, Georgia Power, Southern Power, and the Company by SNG pursuant to these agreements is governed by the terms and conditions of SNG's natural gas tariff and is subject to FERC regulation. For the successor year ended December 31, 2017, transportation revenue under these agreements from SCS and the Company were $136 million and $32 million, respectively. For the successor period of September 1, 2016 through December 31, 2016, transportation revenue under these agreements from SCS and the Company were $32 million and $15 million, respectively. See Note 4 under "Equity Method Investments – SNG" for additional information regarding the Company's investment in SNG.

The Company has an agreement with SCS under which the following services are currently being rendered to the Company as direct or allocated cost: accounting, finance and treasury, tax, information technology, auditing, insurance and pension administration, human resources, systems and procedures, purchasing, and other services. For the successor year ended December 31, 2017 and the successor period of July 1, 2016 through December 31, 2016, costs for these services amounted to $63 million and $17 million, respectively. Cost allocation methodologies have been reported to the FERC and management believes they are reasonable. The FERC permits services to be rendered at cost by system service companies.

SCS, as agent for Alabama Power, Georgia Power, and Southern Power, has agreements with certain subsidiaries of the Company to purchase natural gas. For the successor year ended December 31, 2017, natural gas purchases made by SCS from the Company's subsidiaries were $142 million. For the successor period of July 1, 2016 through December 31, 2016, natural gas purchases made by SCS from the Company's subsidiaries were $27 million.

Regulatory Assets and Liabilities

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

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

| | 2017 | 2016 | Note |
|---|---|---|---|
| | (in millions) | | |
| Environmental remediation | $410 | $411 | (a,b) |
| Retiree benefit plans | 270 | 325 | (a,c) |
| Long-term debt fair value adjustment | 138 | 154 | (d) |
| Under recovered regulatory clause revenues | 98 | 118 | (e) |
| Other regulatory assets | 79 | 58 | (f) |
| Other cost of removal obligations | (1,646) | (1,616) | (g) |
| Deferred income tax credits | (1,063) | (22) | (g,i) |
| Over recovered regulatory clause revenues | (144) | (104) | (e) |
| Other regulatory liabilities | (21) | (39) | (h) |
| Total regulatory assets (liabilities), net | $(1,879) | $(715) | |

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

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

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

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

(d) Recovered over the remaining life of the original debt issuances, which range up to 21 years.

(e) Recorded and recovered or amortized as approved or accepted by the appropriate state regulatory agencies over periods generally not exceeding eight years.

(f) Comprised of several components including unamortized loss on reacquired debt, weather normalization, franchise gas, deferred depreciation expense, and financial instrument-hedging assets, which are recovered or amortized as approved by the applicable state regulatory agencies over periods generally not exceeding 10 years, except for financial hedging-instruments. Financial instrument-hedging assets are recorded over the life of the underlying hedged purchase contracts, which generally do not exceed two years. Upon final settlement, actual costs incurred are recovered, and actual income earned is refunded through the energy cost recovery clause.

(g) Other cost of removal obligations are recorded and deferred income tax liabilities are amortized over the related property lives, which may range up to 80 years. Cost of removal liabilities will be settled and trued up following completion of the related activities.

(h) Comprised of several components including energy efficiency programs, unamortized bond issuance costs and financial instrument-hedging liabilities which are recovered or amortized as approved by the applicable state regulatory agencies over periods generally not exceeding a range of four years to 20 years, except for financial hedging-instruments. Financial instrument-hedging liabilities are recorded over the life of the underlying hedged purchase contracts, which generally do not exceed two years. Upon final settlement, actual costs incurred are recovered, and actual income earned is refunded through the energy cost recovery clause.

(i) Includes excess deferred income tax liabilities not subject to normalization as a result of the Tax Reform Legislation, the recovery and amortization of which will be determined by the applicable state regulatory agencies. See Note 3 under "Regulatory Matters" and Note 5 for additional details.

In the event that a portion of a natural gas distribution utility's operations is no longer subject to applicable accounting rules for rate regulation, the Company would be required to write off to income related regulatory assets and liabilities that are not specifically recoverable through regulated rates. In addition, the 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" for additional information.

Revenues

Gas Distribution Operations

The Company records revenues when goods or services are provided to customers. Those revenues are based on rates approved by the state regulatory agencies of the Company's utilities. As required by the Georgia PSC, Atlanta Gas Light bills Marketers in equal monthly installments for each residential, commercial, and industrial end-use customer's distribution costs as well as for capacity costs utilizing a seasonal rate design for the calculation of each residential end-use customer's annual straight-fixed-variable charge, which reflects the historic volumetric usage pattern for the entire residential class.

All of the natural gas distribution utilities, with the exception of Atlanta Gas Light, have rate structures that include volumetric rate designs that allow the opportunity to recover certain costs based on gas usage. Revenues from sales and transportation services are recognized in the same period in which the related volumes are delivered to customers. Revenues from residential and certain commercial and industrial customers are recognized on the basis of scheduled meter readings. Additionally, unbilled revenues are recognized for estimated deliveries of gas not yet billed to these customers, from the last bill date to the end of the accounting period. For other commercial and industrial customers and for all wholesale customers, revenues are based on actual deliveries to the end of the period.

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. These provisions are referred to as alternative revenue programs and provide for the recognition of certain revenues prior to billing, so long as the amounts recognized will be collected from customers within 24 months of recognition. These programs are as follows:

- Weather normalization adjustments – reduce customer bills when winter weather is colder than normal and increase customer bills when weather is warmer than normal and are included in the tariffs for Virginia Natural Gas, Elizabethtown Gas, and Chattanooga Gas;
- Revenue normalization mechanisms – mitigate the impact of conservation and declining customer usage and are contained in the tariffs for Virginia Natural Gas, Chattanooga Gas, and Elkton Gas; and
- Revenue true-up adjustment – included within the provisions of the Georgia Rate Adjustment Mechanism (GRAM) program in which Atlanta Gas Light participates as a short-term alternative to formal rate case filings, the revenue true-up feature provides for a monthly positive (or negative) adjustment to record revenue in the amount of any variance to budgeted revenues, which are submitted and approved annually as a requirement of GRAM. Such adjustments are reflected in customer billings in a subsequent program year.

Revenue Taxes

The Company charges customers for gas revenue and gas use taxes imposed on the Company and remits amounts owed to various governmental authorities. Gas revenue taxes are recorded at the amount charged to customers, which may include a small administrative fee, as operating revenues, and the related taxes imposed on the Company are recorded as operating expenses on the statements of income. Gas use taxes are excluded from revenue and expense with the related administrative fee included in operating revenues when the tax is imposed on the customer. Revenue taxes included in operating expenses were $98 million and $31 million for the successor year ended December 31, 2017 and the successor period of July 1, 2016 through December 31, 2016, respectively, and $56 million and $101 million for the predecessor periods of January 1, 2016 through June 30, 2016 and the year ended December 31, 2015, respectively.

Gas Marketing Services

The Company recognizes revenues from natural gas sales and transportation services in the same period in which the related volumes are delivered to customers and recognizes sales revenues from residential and certain commercial and industrial customers on the basis of scheduled meter readings. The Company also recognizes unbilled revenues for estimated deliveries of gas not yet billed to these customers from the most recent meter reading date to the end of the accounting period. For other commercial and industrial customers and for all wholesale customers, revenues are based on actual deliveries during the period.

The Company recognizes revenues on 12-month utility-bill management contracts as the lesser of cumulative earned or cumulative billed amounts. Revenues for warranty and repair contracts are recognized on a straight-line basis over the contract term while revenues for maintenance services are recognized at the time such services are performed.

Wholesale Gas Services

The Company nets revenues from energy and risk management activities with the associated costs. Profits from sales between segments are eliminated and are recognized as goods or services sold to end-use customers. The Company records transactions that qualify as derivatives at fair value with changes in fair value recognized in earnings in the period of change and characterized as unrealized gains or losses. Gains and losses on derivatives held for energy trading purposes are presented on a net basis in revenue.

Concentration of Revenue

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

Cost of Natural Gas and Other Sales

Gas Distribution Operations

Excluding Atlanta Gas Light, which does not sell natural gas to end-use customers, the Company 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. The Company 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.

Gas Marketing Services

The Company's gas marketing services' customers are charged for actual or estimated natural gas consumed. Within cost of natural gas, the Company also includes costs of fuel and lost and unaccounted for gas, adjustments to reduce the value of inventories to market value, and gains and losses associated with certain derivatives. The Company records the costs to service its warranty and repair contract claims as cost of other sales.

Income and Other Taxes

The Company uses the liability method of accounting for deferred income taxes and provides deferred income taxes for all significant income tax temporary differences. Federal ITCs utilized are deferred and amortized to income over the average life of the related property. Taxes that are collected from customers on behalf of governmental agencies to be remitted to these agencies are presented on the balance sheet, excluding revenue taxes which are presented on the statements of income. See "Revenues – Gas Distribution Operations – Revenue Taxes" herein for additional information.

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

Property, Plant, and Equipment

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

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

| | 2017 | 2016 |
|---|---|---|
| | (in millions) | |
| Utility plant in service | $13,079 | $11,996 |
| Information technology equipment and software | 366 | 324 |
| Storage facilities | 1,599 | 1,463 |
| Other | 789 | 725 |
| Total other plant in service | 2,754 | 2,512 |
| Total plant in service | $15,833 | $14,508 |

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. The portion of non-working gas used to maintain the structural integrity of the Company's natural gas storage facilities that is considered to be non-recoverable is recorded as depreciable property, plant, and equipment, while the recoverable or retained portion is recorded as non-depreciable property, plant, and equipment.

The amount of non-cash property additions recognized for the successor periods of the year ended December 31, 2017 and July 1, 2016 through December 31, 2016 and the predecessor periods of January 1, 2016 through June 30, 2016 and the year ended December 31, 2015 were $135 million, $63 million, $41 million, and $48 million, respectively. These amounts are comprised of construction-related accounts payable outstanding at the end of each period.

Depreciation and Amortization

Depreciation of the original cost of utility plant in service is provided using composite straight-line rates, which approximated 2.9% in 2017, 2.8% in 2016, and 2.7% in 2015. Depreciation studies are conducted periodically to update the composite rates that are approved by the respective state regulatory agency. 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 asset are retired when the related property unit is retired.

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Depreciation of the original cost of other plant in service is provided primarily on a straight-line basis over the following useful lives: five to 15 years for transportation equipment, 40 to 60 years for storage facilities, and up to 65 years for other assets.

Allowance for Funds Used During Construction

The Company records AFUDC for Atlanta Gas Light, Nicor Gas, Chattanooga Gas, and Elizabethtown Gas, 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 asset through a higher rate base and higher depreciation. All current construction costs are included in rates. The capital expenditures of the other three natural gas utilities do not qualify for AFUDC treatment. The Company's AFUDC composite rates are as follows:

| | Successor | | Predecessor | |
|---|---|---|---|---|
| | Year ended December 31, 2017 | July 1, 2016 through December 31, 2016 | January 1, 2016 through June 30, 2016 | Year ended December 31, 2015 |
| Atlanta Gas Light | 8.10% | 4.05 % | 4.05% | 8.10 % |
| Chattanooga Gas | 7.41 | 3.71 | 3.71 | 7.41 |
| Elizabethtown Gas(*) | 1.56 | 0.84 | 0.84 | 1.69 |
| Nicor Gas(*) | 1.22 | 1.50 | 1.50 | 0.82 |

(*) Variable rate is determined by the FERC method of AFUDC accounting.

Cash payments for interest during the successor periods of the year ended December 31, 2017 and July 1, 2016 through December 31, 2016 and the predecessor periods of January 1, 2016 through June 30, 2016 and the year ended December 31, 2015 totaled $223 million, $135 million, $119 million, and $181 million, respectively.

Impairment of Long-Lived Assets

The Company evaluates long-lived assets for impairment when events or changes in circumstances indicate that the carrying value of such assets may not be recoverable. The determination of whether an impairment has occurred is based on either a specific regulatory disallowance or an estimate of undiscounted future cash flows attributable to the assets, as compared with the carrying value of the assets. If an impairment has occurred, the amount of the impairment recognized is determined by either the amount of regulatory disallowance or by estimating the fair value of the assets and recording a loss if the carrying value is greater than the fair value. For assets identified as held for sale, the carrying value is compared to the estimated fair value less the cost to sell in order to determine if an impairment loss is required. Until the assets are disposed of, their estimated fair value is re-evaluated when circumstances or events change. See Note 3 under "Other Matters" for additional information.

Goodwill and Other Intangible Assets and Liabilities

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. In assessing goodwill for impairment, the Company has the option of first performing a qualitative assessment to determine that it is more likely than not that fair value of its reporting unit exceeds its carrying value (commonly referred to as Step 0). If the Company chooses not to perform a qualitative assessment, or the result of Step 0 indicates a probable decrease in fair value of its reporting unit below its carrying value, a quantitative two-step test is performed (commonly referred to as Step 1 and Step 2). Step 1 compares the fair value of the reporting unit to its carrying value including goodwill. If the carrying value exceeds the fair value, Step 2 is performed to allocate the fair value of the reporting unit to its assets and liabilities in order to determine the implied fair value of goodwill, which is compared to the carrying value of goodwill to calculate an impairment loss, if any. For the 2017 annual impairment test, the Company performed Step 1 of the two-step impairment test, which resulted in the fair value of all its reporting units that have goodwill exceeding their carrying value. For the 2016 and 2015 annual impairment tests, the Company performed the qualitative Step 0 assessment and determined that it was more likely than not that the fair value of all its reporting units with goodwill exceeded their carrying values, and therefore no quantitative assessment was required. In the third quarter 2015, the Company identified potential impairment indicators and performed an interim impairment test for its storage and fuels reporting unit, which resulted in impairment of the full $14 million goodwill balance for that reporting unit.

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Goodwill and other intangible assets consisted of the following:

| | At December 31, 2017 | | | |
|---|---|---|---|---|
| | Estimated Useful Life | Gross Carrying Amount | Accumulated Amortization | Other Intangible Assets, Net |
| | | (in millions) | | |
| Other intangible assets subject to amortization: | | | | |
| Gas marketing services | | | | |
| Customer relationships | 11-16 years | $221 | $ (77) | $ 144 |
| Trade names | 10-28 years | 115 | (9) | 106 |
| Wholesale gas services | | | | |
| Storage and transportation contracts | 1-5 years | 64 | (34) | 30 |
| Total intangible assets subject to amortization | | $400 | $ (120) | $ 280 |
| Goodwill: | | | | |
| Gas distribution operations | | $4,702 | $ — | $ 4,702 |
| Gas marketing services | | 1,265 | — | 1,265 |
| Total goodwill | | $5,967 | $ — | $ 5,967 |

| | At December 31, 2016 | | | |
|---|---|---|---|---|
| | Estimated Useful Life | Gross Carrying Amount | Accumulated Amortization | Other Intangible Assets, Net |
| | | (in millions) | | |
| Other intangible assets subject to amortization: | | | | |
| Gas marketing services | | | | |
| Customer relationships | 11-16 years | $221 | $ (30) | $ 191 |
| Trade names | 10-28 years | 115 | (2) | 113 |
| Wholesale gas services | | | | |
| Storage and transportation contracts | 1-5 years | 64 | (2) | 62 |
| Total intangible assets subject to amortization | | $400 | $ (34) | $ 366 |
| Goodwill: | | | | |
| Gas distribution operations | | $4,702 | $ — | $ 4,702 |
| Gas marketing services | | 1,265 | — | 1,265 |
| Total goodwill | | $5,967 | $ — | $ 5,967 |

Amortization associated with intangible assets for gas marketing services, included in depreciation and amortization, for the successor year ended December 31, 2017 and the successor period of July 1, 2016 through December 31, 2016 and the predecessor periods of January 1, 2016 through June 30, 2016 and the year ended December 31, 2015 was $54 million, $32 million, $8 million, and $18 million, respectively. Amortization of $32 million and $2 million for wholesale gas services was recorded as a reduction to operating revenues for the successor year ended December 31, 2017 and the successor period of July 1, 2016 through December 31, 2016, respectively.

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

| | Amortization (in millions) |
|---|---|
| 2018 | $ 58 |
| 2019 | 40 |
| 2020 | 28 |
| 2021 | 21 |
| 2022 | 17 |

Included in other deferred credits and liabilities on the balance sheets is $91 million of intangible liabilities that were recorded during acquisition accounting for transportation contracts at wholesale gas services. At December 31, 2017, the accumulated amortization of these intangible liabilities was $50 million. The estimated amortization associated with the intangible liabilities that will be recorded in natural gas revenues is as follows:

| | Amortization (in millions) |
|---|---|
| 2018 | $ 24 |
| 2019 | 17 |

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.

Energy Marketing Receivables and Payables

Wholesale gas services provides services to retail gas marketers, wholesale gas marketers, utility companies, and industrial customers. These counterparties utilize netting agreements that enable wholesale gas services to net receivables and payables by counterparty upon settlement. Wholesale gas services also nets across product lines and against cash collateral, provided the master netting and cash collateral agreements include such provisions. While the amounts due from, or owed to, wholesale gas services' counterparties are settled net, they are recorded on a gross basis in the balance sheets as energy marketing receivables and energy marketing payables.

Wholesale gas services has trade and credit contracts that contain minimum credit rating requirements. These credit rating requirements typically give counterparties the right to suspend or terminate credit if the Company's credit ratings are downgraded to non-investment grade status. Under such circumstances, wholesale gas services would need to post collateral to continue transacting business with some of its counterparties. As of December 31, 2017 and 2016, the required collateral in the event of a credit rating downgrade was $8 million and immaterial, respectively.

Wholesale gas services has a concentration of credit risk for services it provides to its counterparties. This credit risk is generally concentrated in 20 of its counterparties and is measured by 30-day receivable exposure plus forward exposure. Counterparty credit risk is evaluated using an S&P equivalent credit rating, which is determined by a process of converting the lower of the S&P or Moody's rating to an internal rating ranging from 9 to 1, with 9 being equivalent to AAA/Aaa by S&P and Moody's, respectively, and 1 being equivalent to D/Default by S&P and Moody's, respectively. A counterparty that does not have an external rating is assigned an internal rating based on the strength of its financial ratios. As of December 31, 2017, the top 20 counterparties represented 48%, or $203 million, of the total counterparty exposure and had a weighted average S&P equivalent rating of A-.

Credit policies were established to determine and monitor the creditworthiness of counterparties, including requirements to post collateral or other credit security, as well as the quality of pledged collateral. Collateral or credit security is most often in the form of cash or letters of credit from an investment-grade financial institution, but may also include cash or U.S. government securities held by a trustee. When wholesale gas services 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 combined with a reasonable measure of the Company's credit risk. Wholesale gas services also uses other netting agreements with certain counterparties with whom it conducts significant transactions.

Receivables and Provision for Uncollectible Accounts

The Company's other trade receivables consist primarily of natural gas sales and transportation services billed to residential, commercial, industrial, and other customers. Customers are billed monthly and payment is due within 30 days. For the majority of receivables, a provision for uncollectible accounts is established based on historical collection experience and other factors. For the remaining receivables, if the Company is aware of a specific customer's inability to pay, a provision for uncollectible accounts is recorded to reduce the receivable balance to the amount the Company reasonably expects to collect. If circumstances change, the estimate of the recoverability of accounts receivable could change as well. Circumstances that could affect this estimate include, but are not limited to, customer credit issues, customer deposits, and general economic conditions. Customers' accounts are written off once they are deemed to be uncollectible.

Nicor Gas

Credit risk exposure at Nicor Gas is mitigated by a bad debt rider approved by the Illinois Commission. The bad debt rider provides for the recovery from (or refund to) customers of the difference between Nicor Gas' actual bad debt experience on an annual basis and the benchmark bad debt expense used to establish its base rates for the respective year.

Atlanta Gas Light

Concentration of credit risk occurs at Atlanta Gas Light for amounts billed for services and other costs to its customers, which consist of 15 Marketers in Georgia. The credit risk exposure to Marketers varies seasonally, with the lowest exposure in the non-peak summer months and the highest exposure in the peak winter months. Marketers are responsible for the retail sale of natural gas to end-use customers in Georgia. The functions of the retail sale of gas include the purchase and sale of natural gas, customer service, billings, and collections. The provisions of Atlanta Gas Light's tariff allow Atlanta Gas Light to obtain credit security support in an amount equal to a minimum of two times a Marketer's highest month's estimated bill from Atlanta Gas Light.

Materials and Supplies

Generally, materials and supplies include propane gas inventory, fleet fuel, and other materials and supplies. Materials are charged to inventory when purchased and then expensed or capitalized to plant, as appropriate, at weighted average cost when installed.

Natural Gas for Sale

The natural gas distribution utilities, with the exception of Nicor Gas, record natural gas inventories on a WACOG basis. In Georgia's competitive environment, Marketers sell natural gas to firm end-use customers at market-based prices. Part of the unbundling process, which resulted from deregulation and provides this competitive environment, is the assignment to Marketers of certain pipeline services that Atlanta Gas Light has under contract. On a monthly basis, Atlanta Gas Light assigns to Marketers the majority of the pipeline storage services that it has under contract, along with a corresponding amount of inventory. Atlanta Gas Light retains and manages a portion of its pipeline storage assets and related natural gas inventories for system balancing and to serve system demand.

Nicor 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 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 the Company's net income. At December 31, 2017, the Nicor Gas LIFO inventory balance was $148 million. Based on the average cost of gas purchased in December 2017, the estimated replacement cost of Nicor Gas' inventory at December 31, 2017 was $264 million. During 2017, Nicor Gas did not liquidate any LIFO-based inventory.

The gas marketing services, wholesale gas services, and all other segments record inventory at LOCOM, with cost determined on a WACOG basis. For these segments, the Company evaluates the weighted average cost of its natural gas inventories against market prices to determine whether any declines in market prices below the WACOG are other than temporary. For any declines considered to be other than temporary, the Company recorded the following LOCOM adjustments to cost of natural gas to reduce the value of its natural gas inventories to market value.

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| | Successor | | Predecessor | |
|---|---|---|---|---|
| | 2017 | July 1, 2016 to December 31, 2016 | January 1, 2016 to June 30, 2016 | 2015 |
| | (in millions) | | (in millions) | |
| Gas marketing services | $ — | $ — | $ — | $ 3 |
| Wholesale gas services | 2 | 1 | 3 | 19 |
| All other | — | — | — | 1 |
| Total LOCOM adjustments | $ 2 | $ 1 | $ 3 | $ 23 |

Fair Value Measurements
The Company has financial and nonfinancial assets and liabilities subject to fair value measurement. The financial assets and liabilities measured and carried at fair value include cash and cash equivalents and derivative instruments. The carrying values of receivables, short and long-term investments, accounts payable, short-term debt, other current assets and liabilities, and accrued interest approximate their respective fair value. The nonfinancial assets and liabilities include pension and other postretirement benefits. See Notes 2 and 9 for additional fair value disclosures.
Fair value is the price that would be received to sell an asset or paid to transfer a liability in an orderly transaction between market participants at the measurement date (exit price). The Company utilizes market data or assumptions that market participants would use in valuing the asset or liability, including assumptions about risk and the risks inherent in the inputs to the valuation technique. These inputs can be readily observable, market corroborated, or generally unobservable. The Company primarily applies the market approach for recurring fair value measurements to utilize the best available information. Accordingly, the Company uses valuation techniques that maximize the use of observable inputs and minimize the use of unobservable inputs. Fair value balances are classified based on the observance of those inputs. The guidance establishes a fair value hierarchy that prioritizes the inputs used to measure fair value. The hierarchy gives the highest priority to unadjusted quoted prices in active markets for identical assets or liabilities (Level 1) and the lowest priority to unobservable inputs (Level 3). The three levels of the fair value hierarchy defined by the guidance are as follows:
Level 1
Quoted prices in active markets for identical assets or liabilities as of the reporting date. Active markets are those in which transactions for the asset or liability occur in sufficient frequency and volume to provide pricing information on an ongoing basis. The Company's Level 1 items consist of exchange-traded derivatives, money market funds, and certain retirement plan assets.
Level 2
Pricing inputs are other than quoted prices in active markets included in Level 1, which are either directly or indirectly observable as of the reporting date. Level 2 includes those financial and commodity instruments that are valued using valuation methodologies. These methodologies are primarily industry-standard methodologies that consider various assumptions, including quoted forward prices for commodities, time value, volatility factors, and current market and contractual prices for the underlying instruments, as well as other relevant economic measures. Substantially all of these assumptions are observable in the marketplace throughout the full term of the instrument, can be derived from observable data, or are supported by observable levels at which transactions are executed in the marketplace. Market price data is obtained from multiple sources in order to value certain Level 2 transactions and this data is

representative of transactions that occurred in the marketplace. Level 2 instruments include shorter tenor exchange-traded and non-exchange-traded derivatives such as over-the-counter (OTC) forwards and options and certain retirement plan assets.

Level 3

Pricing inputs include significant unobservable inputs that may be used with internally developed methodologies to determine management's best estimate of fair value from the perspective of market participants. Level 3 instruments include those that may be more structured or otherwise tailored to customers' needs. Level 3 assets, liabilities, and any applicable transfers are primarily related to the Company's pension and other postretirement benefit plan assets as described in Note 2. Transfers into and out of Level 3 are determined using values at the end of the interim period in which the transfer occurred.

Financial Instruments

The Company uses derivative financial instruments to limit exposure to fluctuations in natural gas prices, weather, interest rates, and commodity prices. All derivative financial instruments are recognized as either assets or liabilities on the balance sheets (shown separately as "Risk Management Activities") and are measured at fair value. See Note 9 for additional information regarding fair value. Derivative contracts that qualify as cash flow hedges of anticipated transactions or are recoverable through the respective state regulatory agency approved 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. Cash flows from derivatives are classified on the statement of cash flows in the same category as the hedged item. See Note 10 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. The Company had no outstanding collateral repayment obligations or rights to reclaim collateral arising from derivative instruments recognized at December 31, 2017.

The Company enters into weather derivative contracts as economic hedges of natural gas revenues in the event of warmer-than-normal weather in the Heating Season. Exchange-traded options are carried at fair value, with changes reflected in natural gas revenues. Non-exchange-traded options are accounted for using the intrinsic value method. Changes in the intrinsic value for non-exchange-traded contracts are also reflected in natural gas revenues in the statements of income.

Wholesale gas services purchases natural gas for storage when the current market price paid to buy and transport natural gas plus the cost to store and finance the natural gas is less than the market price that can be received in the future, resulting in positive net natural gas revenues. NYMEX futures and OTC contracts are used to sell natural gas at that future price to substantially protect the natural gas revenues that will ultimately be realized when the stored natural gas is sold. The Company enters into transactions to secure transportation capacity between delivery points in order to serve its customers and various markets. NYMEX futures and OTC contracts are used to capture the price differential or spread between the locations served by the capacity in order to substantially protect the natural gas revenues that will ultimately be realized when the physical flow of natural gas between delivery points occurs. These contracts generally meet the definition of derivatives and are carried at fair value on the balance sheets, with changes in fair value recorded in natural gas revenues on the statements of income in the period of change. These contracts are not designated as hedges for accounting purposes.

The purchase, transportation, storage, and sale of natural gas are accounted for on a weighted average cost or accrual basis, as appropriate, rather than on the fair value basis utilized for the derivatives used to mitigate the natural gas price risk associated with the storage and transportation portfolio. Monthly demand charges are incurred for the contracted storage and transportation capacity and payments associated with asset management agreements, and these demand charges and payments are recognized on the statements of income in the period they are incurred. This difference in accounting methods can result in volatility in reported earnings, even though the economic margin is substantially unchanged from the dates the transactions were consummated.

The 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, certain changes in pension and other postretirement benefit plans, and reclassifications for amounts included in net income.

Non-Wholly Owned Entities

The Company holds ownership interests in a number of business ventures with varying ownership structures and evaluates all of its partnership interests and other variable interests to determine if each entity is a VIE. If a venture is a VIE for which the Company is the primary beneficiary, the assets, liabilities, and results of operations of the entity are consolidated. The Company reassesses its conclusion as to whether an entity is a VIE upon certain occurrences,

which are deemed reconsideration events under the guidance. See Note 4 under "Variable Interest Entities" for additional information.
For entities that are not determined to be VIEs, the Company evaluates whether it has control or significant influence over the investee to determine the appropriate consolidation and presentation. Generally, entities under the control of the Company are consolidated, and entities over which the Company can exert significant influence, but does not control, are accounted for under the equity method of accounting. However, the Company also invests in partnerships and limited liability companies that maintain separate ownership accounts. All such investments are required to be accounted for under the equity method unless the interest is so minor that there is virtually no influence over operating and financial policies, as are all investments in joint ventures.
Investments accounted for under the equity method are recorded within equity investments in unconsolidated subsidiaries within the other property and investments section in the balance sheets and the equity income is recorded within earnings from equity

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method investments within the other income (expense) section in the statements of income. See Note 4 under "Equity Method Investments" for additional information.

2. RETIREMENT BENEFITS

The Company has a qualified defined benefit, trusteed, pension plan covering most eligible employees, which was closed in 2012 to new employees and reopened to all non-union employees on January 1, 2018. The 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. The Company 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, the Company provides certain medical care and life insurance benefits for eligible retired employees through a postretirement benefit plan. The Company 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.

In connection with the Merger, the Company performed updated valuations of its pension and other postretirement benefit plan assets and obligations to reflect actual census data at the new measurement date of July 1, 2016. This valuation resulted in increases to the projected benefit obligations for the pension and other postretirement benefit plans of approximately $177 million and $20 million, respectively, a decrease in the fair value of pension plan assets of $10 million, and an increase in the fair value of other postretirement benefit plan assets of $1 million. The Company also recorded a related regulatory asset of $437 million related to unrecognized prior service cost and actuarial gain/loss, as it is probable that this amount will be recovered through future rates for the natural gas distribution utilities. The previously unrecognized prior service cost and actuarial gain/loss related to non-utility subsidiaries were eliminated through purchase accounting adjustments.

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 all periods presented and the benefit obligations as of the measurement date are presented below.

| | Successor | | | Predecessor | | |
|---|---|---|---|---|---|---|
| Assumptions used to determine net periodic costs: | Year ended December 31, 2017 | July 1, 2016 through December 31, 2016 | | January 1, 2016 through June 30, 2016 | Year ended December 31, 2015 | |
| Pension plans | | | | | | |
| Discount rate – interest costs[a] | 3.76% | 3.21 | % | 4.00% | 4.20 | % |
| Discount rate – service costs[a] | 4.64 | 4.07 | | 4.80 | 4.20 | |
| Expected long-term return on plan assets | 7.60 | 7.75 | | 7.80 | 7.80 | |
| Annual salary increase | 3.50 | 3.50 | | 3.70 | 3.70 | |
| Pension band increase[b] | N/A | 2.00 | | 2.00 | 2.00 | |
| Other postretirement benefit plans | | | | | | |
| Discount rate – interest costs[a] | 3.40% | 2.84 | % | 3.60% | 4.00 | % |
| Discount rate – service costs[a] | 4.55 | 3.96 | | 4.70 | 4.00 | |
| Expected long-term return on plan assets | 6.03 | 5.93 | | 6.60 | 7.80 | |

| | | | | |
|---|---|---|---|---|
| Annual salary increase | 3.50 | 3.50 | 3.70 | 3.70 |

(a) Effective January 1, 2016, the Company uses a spot rate approach to estimate the service cost and interest cost components. Previously, the Company estimated these components using a single weighted average discount rate.

(b) Only applicable to Nicor Gas union employees. The pension bands for the former Nicor plan reflect the negotiated rates in accordance with the union agreements.

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| Assumptions used to determine benefit obligations: | 2017 | 2016 |
|---|---|---|
| Pension plans | | |
| Discount rate | 3.74% | 4.39% |
| Annual salary increase | 2.88 | 3.50 |
| Pension band increase(*) | N/A | 2.00 |
| Other postretirement benefit plans | | |
| Discount rate | 3.62% | 4.15% |
| Annual salary increase | 2.56 | 3.50 |

(*) Only applicable to Nicor Gas union employees. The pension bands for the former Nicor plan reflect the negotiated rates in accordance with the union agreements.

The Company estimates the expected return on pension plan and other postretirement benefit plan assets by evaluating expected bond returns, equity risk premiums, asset allocations, the effects of active plan management, the impact of periodic plan asset rebalancing, and historical performance. The Company also considers guidance from its investment advisors in making a final determination of its expected rate of return on assets. To the extent the actual rate of return on assets realized over the course of a year is greater or less than the assumed rate, it does not affect that year's annual pension or other postretirement benefit plan cost; rather, this gain or loss reduces or increases future pension or other postretirement benefit plan costs.

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 | 6.40% | 4.50 % | 2038 |
| Post-65 medical | 7.80 | 4.50 | 2038 |
| Post-65 prescription | 7.80 | 4.50 | 2038 |

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:

| | 1 Percent Increase | 1 Percent Decrease |
|---|---|---|
| | (in millions) | |
| Benefit obligation | $11 | $ (10 ) |
| Service and interest costs | — | — |

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Pension Plans

The total accumulated benefit obligation for the pension plans was $1.1 billion at December 31, 2017 and $1.1 billion at December 31, 2016. Changes in the projected benefit obligations and the fair value of plan assets for all periods presented were as follows:

| | Successor | | Predecessor |
|---|---|---|---|
| | Year ended December 31, 2017 | July 1, 2016 through December 31, 2016 | January 1, 2016 through June 30, 2016 |
| | (in millions) | | (in millions) |
| Change in benefit obligation | | | |
| Benefit obligation at beginning of period | $1,133 | $ 1,244 | $ 1,067 |
| Service cost | 23 | 15 | 13 |
| Interest cost | 42 | 20 | 21 |
| Plan amendments | (26) | — | — |
| Benefits paid | (91) | (31) | (26) |
| Actuarial (gain) loss | 103 | (115) | 169 |
| Balance at end of period | 1,184 | 1,133 | 1,244 |
| Change in plan assets | | | |
| Fair value of plan assets at beginning of period | 983 | 837 | 847 |
| Actual return (loss) on plan assets | 175 | 48 | 15 |
| Employer contributions | 1 | 129 | 1 |
| Benefits paid | (91) | (31) | (26) |
| Fair value of plan assets at end of period | 1,068 | 983 | 837 |
| Accrued liability | $116 | $ 150 | $ 407 |

At December 31, 2017, the projected benefit obligations for the qualified and non-qualified pension plans were $1.1 billion and $44 million, respectively. All pension plan assets are related to the qualified pension plan.

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

| | 2017 | 2016 |
|---|---|---|
| | (in millions) | |
| Other regulatory assets, deferred | $217 | $267 |
| Other deferred charges and assets | 85 | 58 |
| Other current liabilities | (3) | (2) |
| Employee benefit obligations | (198) | (206) |

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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.

| | Regulatory Amortization | Prior Service Cost | Net (Gain) Loss |
|---|---|---|---|
| | (in millions) | | |
| Balance at December 31, 2017: | | | |
| Accumulated OCI | $— | $ — | $ (42) |
| Regulatory assets (liabilities) | 40 | (20) | 197 |
| Total | $40 | $ (20) | $ 155 |
| Balance at December 31, 2016: | | | |
| Accumulated OCI | $— | $ — | $ (43) |
| Regulatory assets (liabilities) | — | (2) | 269 |
| Total | $— | $ (2) | $ 226 |
| Estimated amortization in net periodic cost in 2018: | | | |
| Regulatory assets (liabilities) | $3 | $ (2) | $ 16 |

The components of OCI and the changes in the balance of regulatory assets related to the defined benefit pension plans for all periods presented were as follows:

| | Accumulated OCI | Regulatory Assets |
|---|---|---|
| | (in millions) | |
| Predecessor – Balance at December 31, 2015: | $282 | $ 88 |
| Reclassification adjustments: | | |
| Amortization of prior service costs | 1 | — |
| Amortization of net loss | (9) | (4) |
| Total reclassification adjustments | (8) | (4) |
| Total change | (8) | (4) |
| Predecessor – Balance at June 30, 2016: | $274 | $ 84 |
| | | |
| Successor – Balance at July 1, 2016: | $— | $ 368 |
| Net (gain) loss | (43) | (87) |
| Reclassification adjustments: | | |
| Amortization of prior service costs | — | 1 |
| Amortization of net loss | — | (15) |
| Total reclassification adjustments | — | (14) |
| Total change | (43) | (101) |
| Successor – Balance at December 31, 2016: | $(43) | $ 267 |
| Net (gain) loss | 1 | (31) |
| Reclassification adjustments: | | |
| Amortization of regulatory assets | — | (1) |
| Amortization of net loss | — | (18) |
| Total reclassification adjustments | — | (19) |

| | | |
|---|---|---|
| Total change | 1 | (50 ) |
| Successor – Balance at December 31, 2017: | $(42 ) | $ 217 |

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Components of net periodic pension costs for all periods presented were as follows:

| | Successor | | Predecessor | |
|---|---|---|---|---|
| | Year ended December 31, 2017 | July 1, 2016 through December 31, 2016 | January 1, 2016 through June 30, 2016 | Year ended December 31, 2015 |
| | (in millions) | | (in millions) | |
| Service cost | $23 | $ 15 | $13 | $ 28 |
| Interest cost | 42 | 20 | 21 | 45 |
| Expected return on plan assets | (70) | (35) | (33) | (65) |
| Amortization of regulatory assets | 1 | — | — | — |
| Amortization: | | | | |
| Prior service costs | — | (1) | (1) | (2) |
| Net (gain)/loss | 18 | 14 | 13 | 31 |
| Net periodic pension cost | $14 | $ 13 | $13 | $ 37 |

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.

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:

| | Benefit Payments |
|---|---|
| | (in millions) |
| 2018 | $ 100 |
| 2019 | 77 |
| 2020 | 79 |
| 2021 | 79 |
| 2022 | 80 |
| 2023 to 2027 | 392 |

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Other Postretirement Benefits

Changes in the APBO and the fair value of plan assets for all periods presented were as follows:

| | Successor | | Predecessor |
|---|---|---|---|
| | Year ended December 31, 2017 | July 1, 2016 through December 31, 2016 | January 1, 2016 through June 30, 2016 |
| | (in millions) | | (in millions) |
| Change in benefit obligation | | | |
| Benefit obligation at beginning of period | $308 | $ 338 | $ 318 |
| Service cost | 2 | 1 | 1 |
| Interest cost | 10 | 5 | 5 |
| Benefits paid | (19 ) | (11 ) | (11 ) |
| Actuarial (gain) loss | 3 | (26 ) | 24 |
| Plan amendments | 3 | — | — |
| Employee contributions | 3 | 1 | 1 |
| Balance at end of period | 310 | 308 | 338 |
| Change in plan assets | | | |
| Fair value of plan assets at beginning of period | 105 | 100 | 99 |
| Actual return (loss) on plan assets | 20 | 4 | 1 |
| Employee contributions | 3 | 1 | 1 |
| Employer contributions | 17 | 11 | 10 |
| Benefits paid | (20 ) | (11 ) | (11 ) |
| Fair value of plan assets at end of year | 125 | 105 | 100 |
| Accrued liability | $185 | $ 203 | $ 238 |

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:

| | 2017 | 2016 |
|---|---|---|
| | (in millions) | |
| Other regulatory assets, deferred | $46 | $52 |
| Employee benefit obligations | (185) | (203) |

Presented below are the amounts included in accumulated OCI and regulatory assets 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. The estimated amortization of such amounts for 2018 is immaterial.

| | Regulatory Amortization | Prior Service Cost | Net (Gain) Loss |
|---|---|---|---|
| | (in millions) | | |
| Balance at December 31, 2017: | | | |
| Accumulated OCI | $— | $ — | $ (3 ) |
| Regulatory assets (liabilities) | 6 | (7 ) | 47 |
| Total | $6 | $ (7 ) | $ 44 |

| | | | |
|---|---|---|---|
| Balance at December 31, 2016: | | | |
| Accumulated OCI | $— | $ — | $ (3 ) |
| Regulatory assets (liabilities) | — | (12 ) | 64 |
| Total | $— | $ (12 ) | $ 61 |

NOTES (continued)
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The components of OCI, along with the changes in the balance of regulatory assets (liabilities), related to the other postretirement benefit plans for all periods presented were as follows:

| | Accumulated OCI (in millions) | Regulatory Assets |
|---|---|---|
| Predecessor – Balance at December 31, 2015: | $ 36 | $ 30 |
| Net (gain) loss | — | — |
| Reclassification adjustments: | | |
| Amortization of prior service costs | — | 1 |
| Amortization of net loss | (1) | (1) |
| Total reclassification adjustments | (1) | — |
| Total change | (1) | — |
| Predecessor – Balance at June 30, 2016: | $ 35 | $ 30 |
| | | |
| Successor – Balance at July 1, 2016: | $ — | $ 77 |
| Net (gain) loss | (3) | (23) |
| Reclassification adjustments: | | |
| Amortization of prior service costs | — | 1 |
| Amortization of net loss | — | (3) |
| Total reclassification adjustments | — | (2) |
| Total change | (3) | (25) |
| Successor – Balance at December 31, 2016: | $ (3) | $ 52 |
| Net (gain) loss | — | (5) |

| | | |
|---|---|---|
| Reclassification adjustments: | | |
| Amortization of prior service costs | — | 3 |
| Amortization of net loss | — | (4) |
| Total reclassification adjustments | — | (1) |
| Total change | — | (6) |
| Successor – Balance at December 31, 2017: | $ (3) | $ 46 |

Components of the other postretirement benefit plans' net periodic cost for all periods presented were as follows:

| | Successor | | Predecessor | |
|---|---|---|---|---|
| | Year ended December 31, 2017 | July 1, 2016 through December 31, 2016 | January 1, 2016 through June 30, 2016 | Year ended December 31, 2015 |
| | (in millions) | | (in millions) | |
| Service cost | $ 2 | $ 1 | $ 1 | $ 2 |
| Interest cost | 10 | 5 | 5 | 13 |
| Expected return on plan assets | (7) | (3) | (3) | (7) |
| Amortization of regulatory assets | — | 2 | — | — |
| Amortization: | | | | |
| Prior service costs | (3) | — | (1) | (3) |
| Net (gain)/loss | 4 | — | 2 | 6 |
| Net periodic postretirement benefit cost | $ 6 | $ 5 | $ 4 | $ 11 |

NOTES (continued)
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Future benefit payments, including prescription drug benefits, reflect expected future service and are estimated based on assumptions used to measure the APBO for the other postretirement benefit plans. At December 31, 2017, estimated benefit payments were as follows:

| | Benefit Payments (in millions) |
|---|---|
| 2018 | $ 20 |
| 2019 | 20 |
| 2020 | 21 |
| 2021 | 21 |
| 2022 | 22 |
| 2023 to 2027 | 105 |

Benefit Plan Assets

Pension plan and other postretirement benefit plan assets are managed and invested in accordance with all applicable requirements, including ERISA and the Internal Revenue Code of 1986, as amended. The Company's investment policies for both the pension plan and the other postretirement benefit plans cover a diversified mix of assets, including equity and fixed income securities, real estate, and private equity. The Company minimizes the risk of large losses primarily through diversification but also monitors and manages other aspects of risk.

The composition of the Company's pension plan and other postretirement benefit plan assets as of December 31, 2017 and 2016, along with the targets for each plan, 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 % |
| 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 % |

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

NOTES (continued)
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Investment Strategies

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

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

The investment strategies for the predecessor periods followed a policy to preserve the plans' capital and maximize investment earnings in excess of inflation within acceptable levels of capital market volatility. To accomplish this goal, the plans' assets were managed to optimize long-term return while maintaining a high standard of portfolio quality and diversification. In developing the allocation policy for the assets of the pension and other postretirement benefit plans, the Company examined projections of asset returns and volatility over a long-term horizon. In connection with this analysis, the risk and return trade-offs of alternative asset classes and asset mixes were evaluated given long-term historical relationships as well as prospective capital market returns. The Company also conducted asset-liability studies to match projected asset growth with projected liability growth to determine whether there is sufficient liquidity for projected benefit payments. Asset mix guidelines were developed by incorporating the results of these analyses with an assessment of the Company's risk posture, and taking into account industry practices. The Company periodically evaluated its investment strategy to ensure that plan assets were sufficient to meet the benefit obligations of the plans. As part of the ongoing evaluation, the Company made changes to its targeted asset allocations and investment strategy.

Benefit Plan Asset Fair Values

Following are the fair value measurements for the pension plan and the other postretirement benefit plan assets as of December 31, 2017 and 2016. 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 for the successor period, 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. Management believes the portfolio is well-diversified with no significant concentrations of risk.

Valuation methods of the primary fair value measurements disclosed in the following tables are as follows:

- Domestic and international equity. Investments in equity securities such as common stocks, American depositary receipts, and real estate investment trusts that trade on a public exchange are classified as Level 1 investments and are valued at the closing price in the active market. Equity investments with unpublished prices (i.e. pooled funds) are valued as Level 2, when the underlying holdings used to value the investment are comprised of Level 1 or Level 2 equity securities.
- Fixed income. Investments in fixed income securities are generally classified as Level 2 investments and are valued based on prices reported in the market place. Additionally, the value of fixed income securities takes into consideration certain items such as broker quotes, spreads, yield curves, interest rates, and discount rates that apply to the term of a specific instrument.
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Real estate investments, private equity, and special situations investments. Investments in real estate, private equity, and special situations are generally classified as Net Asset Value as a Practical Expedient, since the underlying assets typically do not have publicly available observable inputs. The fund manager values the assets using various inputs and techniques depending on the nature of the underlying investments. Techniques may include purchase multiples for comparable transactions, comparable public company trading multiples, discounted cash flow analysis, prevailing market capitalization rates, recent sales of comparable investments, and independent third-party appraisals. The fair value of partnerships is determined by aggregating the value of the underlying assets less liabilities.

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The fair values of pension plan assets as of December 31, 2017 and 2016 are presented below. These fair value measurements exclude cash, receivables related to investment income, pending investments sales, and payables related to pending investment purchases. For 2017 and 2016, special situations (absolute return and hedge funds) investment assets are presented in the table 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.

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The fair values of 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 investments sales, and payables related to pending investment purchases. For 2017 and 2016, special situations (absolute return and hedge funds) investment assets are presented in the table 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.

Employee Savings Plan

SCS sponsors 401(k) defined contribution plans covering certain eligible Southern Company Gas employees. Through December 31, 2017, the 401(k) plans provided matching contributions of either 65% on up to 8% of an employee's eligible compensation, or a 100% matching contribution on up to 3% of an employee's eligible compensation, followed by a 75% matching contribution on up to the next 3% of an employee's eligible compensation. Total matching contributions made to the 401(k) plans for the successor periods ended December 31, 2017 and 2016 were $17 million and $8 million, respectively, and for the predecessor periods ended June 30, 2016 and December 31, 2015 were $10 million and $16 million, respectively.

For employees not accruing a benefit under the pension plan, additional contributions made to the 401(k) plans for the successor period ended December 31, 2017 were $2 million, for the successor period ended December 31, 2016 were not material, and for the predecessor periods ended June 30, 2016 and December 31, 2015 were $2 million for each period.

Effective January 1, 2018, the 401(k) plans were merged into the Southern Company Employee Savings Plan, which is a defined contribution plan covering substantially all employees of the Company. Under this plan, the Company matches a portion of the first 6% of employee base salary contributions. The maximum Company match is 5.1% of an employee's base salary.

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3. CONTINGENCIES AND REGULATORY MATTERS
General Litigation Matters
Nicor Gas and Nicor Energy Services Company, wholly-owned subsidiaries of the Company, and Nicor Inc. were defendants in a putative class action initially filed in 2011 in the state court in Cook County, Illinois. The plaintiffs purported to represent a class of the customers who purchased the Gas Line Comfort Guard product from Nicor Energy Services Company and variously alleged that the marketing, sale, and billing of the Gas Line Comfort Guard product violated the Illinois Consumer Fraud and Deceptive Business Practices Act, constituting common law fraud and resulting in unjust enrichment of these entities. The plaintiffs sought, on behalf of the classes they purported to represent, actual and punitive damages, interest, costs, attorney fees, and injunctive relief. On February 8, 2017, the judge denied the plaintiffs' motion for class certification and the Company's motion for summary judgment. On March 7, 2017, the parties reached a settlement, which was finalized and effective on April 3, 2017. The settlement did not have a material impact on the Company's financial statements.
The Company is assessing its alleged involvement in an incident that occurred in one of its service territories that resulted in several deaths, injuries, and property damage. One of the Company's utilities has been named as one of the defendants in several lawsuits related to this incident. The Company has insurance that provides full coverage of any financial exposure in excess of $11 million that is related to this incident. During the successor period ended December 31, 2016 and the predecessor period ended December 31, 2015, the Company recorded reserves for substantially all of its potential exposure from these cases. The ultimate outcome of this matter cannot be determined at this time.
The Company is subject to certain claims and legal actions arising in the ordinary course of business. The ultimate outcome of these matters and such pending or potential litigation against the Company cannot be determined at this time; however, for current proceedings not specifically reported herein, management does not anticipate that the ultimate liabilities, if any, arising from such current proceedings would have a material effect on the Company's financial statements.
Environmental Matters
The Company'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 Company 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 impact future results of operations, cash flows, and financial condition. Compliance costs may result from the installation of additional environmental controls. Compliance with these environmental requirements involves significant capital and operating costs to clean up affected sites. The Company conducts studies to determine the extent of any required clean up and has recognized in its financial statements the costs to clean up known impacted sites. The natural gas distribution utilities in Illinois, New Jersey, Georgia, and Florida have each received authority from their applicable state regulatory agencies to recover approved environmental compliance costs through regulatory mechanisms.
The Company is subject to environmental remediation liabilities associated with 46 former MGP sites in five different states. Accrued environmental remediation costs of $388 million and $426 million have been recorded in the balance sheets as of December 31, 2017 and 2016, respectively. These environmental remediation expenditures are recoverable from customers through rate mechanisms approved by the applicable state regulatory agencies, with the exception of one site representing $2 million of the accrued remediation costs.
In 2015, the EPA filed an administrative complaint and notice of opportunity for hearing against Nicor Gas. The complaint alleged violation of the regulatory requirements applicable to polychlorinated biphenyls in the Nicor Gas distribution system and the EPA sought a total civil penalty of $0.3 million. On January 26, 2017, the EPA notified Nicor Gas that it agreed to voluntarily dismiss its administrative complaint with prejudice and without payment of a

civil penalty or other further obligation on the part of Nicor Gas.
The Company's ultimate environmental compliance strategy and future environmental capital expenditures will be affected by the final requirements of new or revised environmental regulations and the outcome of any legal challenges to the environmental rules. The ultimate outcome of these matters cannot be determined at this time.
FERC Matters
At December 31, 2017, gas midstream operations was involved in two gas pipeline construction projects. These projects, along with the Company's 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

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areas served. On October 13, 2017, the Atlantic Coast Pipeline project received FERC approval. On January 19, 2018, the PennEast Pipeline project received FERC approval.

Additionally, 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 for additional information.

Regulatory Matters

Regulatory Infrastructure Programs

The Company has infrastructure improvement programs at several of its utilities. Descriptions of these programs are as follows:

Nicor Gas

In 2013, Illinois enacted legislation that allows Nicor Gas to provide more widespread safety and reliability enhancements to its distribution system. The legislation stipulates that rate increases to customers as a result of any infrastructure investments shall not exceed a cumulative annual average of 4.0% or, in any given year, 5.5%, of base rate revenues. In 2014, the Illinois Commission approved the nine-year regulatory infrastructure program, Investing in Illinois, under which Nicor Gas implemented rates that became effective in March 2015.

Investing in Illinois is subject to annual review by the Illinois Commission. In conjunction with the base rate case order issued by the Illinois Commission on January 31, 2018, Nicor Gas is recovering the portion of these program costs incurred prior to December 31, 2017 through base rates. See "Base Rate Cases" herein for additional information.

Atlanta Gas Light

Atlanta Gas Light's STRIDE program, which was initially approved by the Georgia PSC in 2009, is comprised of the Integrated System Reinforcement Program (i-SRP), the Integrated Customer Growth Program (i-CGP), and the Integrated Vintage Plastic Replacement Program (i-VPR) and consists of infrastructure development, enhancement, and replacement programs that are used to update and expand distribution systems and LNG facilities, improve system reliability, and meet operational flexibility and growth. For 2017 and subsequent years, the recovery of and return on current and future capital investments under the STRIDE program are included in the annual base rate revenue adjustment under GRAM.

The i-CGP program authorized Atlanta Gas Light to spend $91 million through 2017 on projects to extend its pipeline facilities to serve customers in areas without pipeline access and create new economic development opportunities in Georgia. This program ended in 2017 and was replaced with a tariff to provide up to $15 million annually for Atlanta Gas Light to commit to strategic economic development projects.

The i-SRP program authorized $445 million of capital spending through 2017 for projects to upgrade Atlanta Gas Light's distribution system and LNG facilities in Georgia, improve its peak-day system reliability and operational flexibility, and create a platform to meet long-term forecasted growth. In August 2016, Atlanta Gas Light filed a petition with the Georgia PSC for approval of a four-year extension of its i-SRP seeking approval to invest an additional $177 million to improve and upgrade its core gas distribution system in years 2017 through 2020.

The i-VPR program authorized Atlanta Gas Light to spend $275 million through 2017 to replace 756 miles of aging plastic pipe that was installed primarily in the mid-1960s to the early 1980s. Atlanta Gas Light has identified approximately 3,300 miles of vintage plastic mains in its system that should be considered for potential replacement. See "Base Rate Cases" herein for additional information.

The orders for the STRIDE programs provide for recovery of all prudent costs incurred in the performance of the program. Atlanta Gas Light will recover from end-use customers, through billings to Marketers, the costs related to the programs net of any cost savings from the programs. The regulatory asset represents recoverable incurred costs related to the programs that will be collected in future rates charged to customers through the rate riders. The future expected costs to be recovered through rates related to allowed, but not incurred costs, are recognized in an unrecognized ratemaking amount that is not reflected on the balance sheets. This allowed cost is primarily the equity

return on the capital investment under the program. See "Unrecognized Ratemaking Amounts" herein for additional information.
Atlanta Gas Light capitalizes and depreciates the capital expenditure costs incurred from the STRIDE programs over the life of the assets. Operations and maintenance costs are expensed as incurred. Recoveries, which are recorded as revenue, are based on a formula that allows Atlanta Gas Light to recover operations and maintenance costs in excess of those included in its current base rates, depreciation, and an allowed rate of return on capital expenditures. However, Atlanta Gas Light is allowed the recovery of carrying costs on the under recovered balance resulting from the timing difference.

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Elizabethtown Gas

Elizabethtown Gas' 2013 extension of the Aging Infrastructure Replacement (AIR) enhanced infrastructure program allowed for infrastructure investment of $115 million over four years and was focused on the replacement of aging cast iron in its pipeline system. Carrying charges on the additional capital spend are being accrued and deferred for regulatory purposes at a weighted average cost of capital of 6.65%. Effective July 1, 2017, investments under this program, which ended September 30, 2017, are being recovered through base rate revenues. See "Base Rate Cases" herein for additional information.

In 2015, Elizabethtown Gas filed the Safety, Modernization and Reliability Tariff plan with the New Jersey BPU seeking approval to invest more than $1.1 billion to replace 630 miles of vintage cast iron, steel, and copper pipeline, as well as 240 regulator stations. During the first quarter 2018, Elizabethtown Gas withdrew this filing in response to a proposed rule by the New Jersey BPU to incentivize utilities to accelerate investment in infrastructure replacement programs that enhance reliability, resiliency, and/or safety of the distribution system. The ultimate outcome of this matter cannot be determined at this time.

Virginia Natural Gas

In 2012, the Virginia Commission approved the Steps to Advance Virginia's Energy (SAVE) program, an accelerated infrastructure replacement program, to be completed over a five-year period. This program included a maximum allowance for capital expenditures of $25 million per year, not to exceed $105 million in total.

In March 2016, the Virginia Commission approved an extension to the SAVE program for Virginia Natural Gas to replace more than 200 miles of aging pipeline infrastructure and invest up to $30 million in 2016 and up to $35 million annually through 2021.

The SAVE program is subject to annual review by the Virginia Commission. In conjunction with the base rate case order issued by the Virginia Commission on December 21, 2017, Virginia Natural Gas is recovering the portion of these program costs incurred prior to September 1, 2017 through base rates. See "Base Rate Cases" herein for additional information.

Florida City Gas

In 2015, the Florida PSC approved Florida City Gas' Safety, Access, and Facility Enhancement program, under which costs incurred for replacing aging pipes are recovered through a rate rider with annual adjustments and true-ups. Under the program, Florida City Gas is authorized to spend $105 million over a 10-year period on infrastructure relocation and enhancement projects.

PRP Settlement

In 2015, Atlanta Gas Light received a final order from the Georgia PSC for a rate true-up of allowed unrecovered revenue through 2014 related to its PRP. This order allows Atlanta Gas Light to recover $144 million of the $178 million previously unrecovered program revenue. The remaining $34 million requested related primarily to previously unrecognized ratemaking amounts and did not have a material impact on the Company's financial statements. The Company also recognized $1 million of interest expense and $5 million in operations and maintenance expense related to the PRP on the Company's statements of income for the predecessor year ended December 31, 2015. See "Unrecognized Ratemaking Amounts" herein for additional information.

As a result of the PRP settlement, Atlanta Gas Light began recovering incremental PRP surcharge amounts through three phased in increases in addition to its previously existing PRP surcharge amount, which was established to address recovery of the unrecovered PRP balance of $144 million in 2015 and the estimated amounts to be earned under the program through 2025. The initial incremental surcharge of approximately $15 million annually was effective in October 2015, with additional annual increases of approximately $15 million in each of October 2016 and 2017. The final increase scheduled for October 2017 was included in the implementation of GRAM in March 2017. The under recovered balance is the result of the continued revenue requirement earned under the program offset by the existing and incremental PRP surcharges. The unrecovered balance at December 31, 2017 was $187 million, including

$104 million of unrecognized equity return. The PRP surcharge will remain in effect until the earlier of the full recovery of the under recovered amount or December 31, 2025. See "Base Rate Cases" herein for additional information on GRAM.

One of the capital projects under the PRP experienced construction issues and Atlanta Gas Light was required to complete mitigation work prior to placing it in service. These mitigation costs will be included in future base rates in 2018. Provisions in the order resulted in the recognition of $5 million in operations and maintenance expense for the predecessor year ended December 31, 2015 on the Company's statements of income. In 2017, Atlanta Gas Light recovered $20 million from the settlement of contractor litigation claims and continues to pursue contractual and legal claims against a third-party contractor. Mitigation costs recovered through the legal process are retained by Atlanta Gas Light. The ultimate outcome of this matter cannot be determined at this time.

Base Rate Cases

Settled Base Rate Cases

On February 21, 2017, the Georgia PSC approved GRAM and a $20 million increase in annual base rate revenues for Atlanta Gas Light, effective March 1, 2017. GRAM adjusts base rates annually, up or down, using an earnings band based on the previously approved ROE of 10.75% and does not collect revenue through special riders and surcharges. Atlanta Gas Light adjusts rates up to the lower end of the band of 10.55% and adjusts rates down to the higher end of the band of 10.95%. Various infrastructure programs previously authorized by the Georgia PSC under Atlanta Gas Light's STRIDE program, which include the i-VPR and i-SRP, will continue under GRAM and the recovery of and return on the infrastructure program investments will be included in annual base rate adjustments. The Georgia PSC will review Atlanta Gas Light's performance annually under GRAM.

Pursuant to the GRAM approval, Atlanta Gas Light and the staff of the Georgia PSC agreed to a variation to the i-CGP that was formerly part of Atlanta Gas Light's STRIDE program. As a result, a new tariff was created, effective October 10, 2017, to provide up to $15 million annually for Atlanta Gas Light to commit to strategic economic development projects. Projects under this tariff must be approved by the Georgia PSC.

Beginning with the next rate adjustment in June 2018, Atlanta Gas Light's recovery of the previously unrecovered Pipeline Replacement Program revenue through 2014, as well as the mitigation costs associated with the Pipeline Replacement Program that were not previously included in its rates, will also be included in GRAM. In connection with the GRAM approval, the last monthly Pipeline Replacement Program surcharge increase became effective March 1, 2017.

On June 30, 2017, the New Jersey BPU approved a settlement that provides for a $13 million increase in annual base rate revenues, effective July 1, 2017, based on a ROE of 9.6%. Also included in the settlement was a new composite depreciation rate that is expected to result in a $3 million annual reduction of depreciation. See Note 11 under "Proposed Sale of Elizabethtown Gas and Elkton Gas" for information on the proposed sale of Elizabethtown Gas.

On December 21, 2017, the Virginia Commission approved a settlement for a $34 million increase in annual base rate revenues, effective September 1, 2017, including $13 million related to the recovery of investments under the SAVE program. See "Regulatory Infrastructure Programs" herein for additional information. An authorized ROE range of 9.0% to 10.0% with a midpoint of 9.5% will be used to determine the revenue requirement in any filing, other than for a change in base rates.

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

Pending Base Rate Cases

On October 23, 2017, Florida City Gas filed a general base rate case with the Florida PSC requesting a $19 million increase in annual base rate revenues. On January 29, 2018, Florida City Gas filed an update to incorporate the effects of the Tax Reform Legislation that, if approved, would reduce the requested base rate revenues by $4 million. The requested increase is based on a 2018 projected test year and a ROE of 11.25%. The requested increase includes $3 million related to the recovery of investments under SAFE that are currently being recovered through a surcharge. Additionally, Florida City Gas requested an interim rate increase of $5 million annually that was approved and became effective January 12, 2018, subject to refund. The Florida PSC is expected to rule on the requested increase in mid-2018.

On December 1, 2017, Atlanta Gas Light filed its 2018 annual rate adjustment with the Georgia PSC. If approved, 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.

On February 15, 2018, Chattanooga Gas filed a general base rate case with the Tennessee Public Utility Commission requesting a $7 million increase in annual base rate revenues. The requested increase, which incorporated the effects of the Tax Reform Legislation, was based on a projected test year ending June 30, 2019 and a ROE of 11.25%. The Tennessee Public Utility Commission is expected to rule on the requested increase in the third quarter 2018.

The ultimate outcome of these pending base rate cases cannot be determined at this time.

Other

The New Jersey BPU, Virginia Commission, Tennessee Public Utility Commission, and Maryland PSC each issued an order effective January 1, 2018 that requires utilities in their respective states to track as a regulatory liability the impact of the Tax Reform Legislation, including the reduction in the corporate income tax rate to 21% and the impact of excess deferred income

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taxes. The New Jersey BPU's order requires Elizabethtown Gas to file by March 2, 2018 proposed revised base rates with an April 1, 2018 interim effective date and a July 1, 2018 final effective date. Virginia Natural Gas will address the Virginia Commission's order in its Annual Information Filing, which will be filed by July 1, 2018. The Tennessee Public Utility Commission's order required Chattanooga Gas to file proposals to reduce rates or make other ratemaking adjustments to account for the impact of the Tax Reform Legislation. Chattanooga Gas made the required filing as part of its February 15, 2018 general base rate case filing. The Maryland PSC's order required Elkton Gas to file an explanation of the impact of the Tax Reform Legislation on its expenses and revenues, as well as when and how it expects to pass through to its customers those effects. Elkton Gas made the required filing on February 15, 2018 and will reduce annual base rates by $0.1 million effective April 1, 2018. Credits will be issued to customers for the impact of the Tax Reform Legislation from January 2018 through March 2018.
The Illinois 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 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.
The ultimate outcome of these matters cannot be determined at this time.

energySMART

In 2014, the Illinois Commission approved Nicor Gas' energySMART through 2017, which outlined energy efficiency program offerings and therm reduction goals, and subsequently extended the program to 2021. Through December 31, 2017, Nicor Gas spent $107 million of the initial authorized expenditure of $113 million. A new four-year program began on January 1, 2018, with an additional authorized expenditure of $160 million.

Unrecognized Ratemaking Amounts

The following table illustrates the Company's authorized ratemaking amounts that are not recognized on its balance sheets. These amounts are primarily composed of an allowed equity rate of return on assets associated with certain of the Company's regulatory infrastructure programs. These amounts will be recognized as revenues in the Company's financial statements in the periods they are billable to customers, the majority of which will be recovered by 2025.

| | December 31, 2017 | December 31, 2016 |
|---|---|---|
| | (in millions) | |
| Atlanta Gas Light | $ 104 | $ 110 |
| Virginia Natural Gas | 11 | 11 |
| Elizabethtown Gas(*) | 8 | 6 |
| Nicor Gas | 2 | 2 |
| Total | $ 125 | $ 129 |

(*) See Note 11 under "Proposed Sale of Elizabethtown Gas and Elkton Gas" for information on the pending asset sale.

Other Matters

A wholly-owned subsidiary of the Company 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 the Company 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 the Company's 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 material impact on the Company's financial statements.

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4. JOINT OWNERSHIP AGREEMENTS
In 2014, the Company entered into a construction and ownership arrangement associated with the Dalton Pipeline through which the Company has a 50% undivided ownership interest jointly with The Williams Companies, Inc. in the 115-mile Dalton Pipeline to serve as an extension of the Transco natural gas pipeline system into northwest Georgia. The Company also 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, the Company 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. At December 31, 2017, the net book value of the Company's 50% share of the pipeline was $252 million and is reflected in total property, plant, and equipment in the balance sheet. At December 31, 2016, the net book value of the Company's 50% share of the pipeline was $124 million and is reflected in construction work in progress in the balance sheet.
Variable Interest Entities
SouthStar, previously a joint venture owned 85% by the Company and 15% by Piedmont, was the only VIE for which the Company was the primary beneficiary, prior to October 2016 when the Company completed its purchase of Piedmont's remaining interest in SouthStar.
In 2015, Georgia Natural Gas Company (GNG), a 100%-owned, direct subsidiary of the Company, notified Piedmont of its election, pursuant to a change in control of SouthStar, to purchase Piedmont's 15% interest in SouthStar at fair market value. This purchase was contingent upon the closing of the merger between Piedmont and Duke Energy Corporation (Duke Energy). In October 2016, after Piedmont and Duke Energy completed their merger, GNG completed its purchase of Piedmont's interest in SouthStar and paid a purchase price of $160 million and $15 million for Piedmont's share of SouthStar's 2016 earnings through the date of acquisition.
At December 31, 2015, the Company presented the noncontrolling interest related to Piedmont's interest in SouthStar as a component in equity. During the first quarter 2016, the Company reclassified its noncontrolling interest, whose redemption was beyond the Company's control, as a contingently redeemable noncontrolling interest. Upon Piedmont and Duke Energy obtaining the necessary merger approval, the Company deemed this noncontrolling interest to be mandatorily redeemable and reclassified it to a current liability during the third quarter 2016. The roll-forwards of the redeemable noncontrolling interest for the successor period of July 1, 2016 through December 31, 2016 and the predecessor period of January 1, 2016 through June 30, 2016 are detailed below:

| Predecessor – | (in millions) |
|---|---|
| Balance at December 31, 2015 | $ — |
| Reclassification of noncontrolling interest to contingently redeemable noncontrolling interest | 46 |
| Net income attributable to noncontrolling interest | 14 |
| Distribution to noncontrolling interest | (19) |
| Balance at June 30, 2016 | $ 41 |

| Successor – | (in millions) |
|---|---|
| Balance at July 1, 2016 | $ 174 |
| Reclassification of contingently redeemable noncontrolling interest to mandatorily redeemable noncontrolling interest | (174) |
| Balance at December 31, 2016 | $ — |

The Company's cash flows used for financing activities included SouthStar's distribution to Piedmont for its portion of SouthStar's annual earnings from the previous year, which generally occurred in the first quarter of each year. For the successor period of July 1, 2016 through December 31, 2016, SouthStar made a distribution of $15 million upon completion of the purchase of Piedmont's interest in SouthStar. For the predecessor periods of January 1, 2016 through June 30, 2016 and the year ended December 31, 2015, SouthStar distributed to Piedmont $19 million and $18 million, respectively.

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Equity Method Investments

The carrying amounts of the Company's equity method investments as of December 31, 2017 and 2016 and related income from those investments for the successor periods of the year ended December 31, 2017 and July 1, 2016 through December 31, 2016 and predecessor periods of January 1, 2016 through June 30, 2016 and the year ended December 31, 2015 were as follows:

| Balance Sheet Information | December 31, 2017 | December 31, 2016 |
|---|---|---|
| | (in millions) | |
| SNG(*) | $1,262 | $ 1,394 |
| Triton | 42 | 44 |
| Horizon Pipeline | 30 | 30 |
| PennEast Pipeline | 57 | 22 |
| Atlantic Coast Pipeline | 41 | 33 |
| Pivotal JAX LNG, LLC | 44 | 16 |
| Other | 1 | 2 |
| Total | $1,477 | $ 1,541 |

(*) Includes a $104 million decrease at December 31, 2017 related to the impact of the Tax Reform Legislation and new income tax apportionment factors in several states resulting from the Company's inclusion in the consolidated Southern Company state tax filings.

| Income Statement Information | Successor | | Predecessor | |
|---|---|---|---|---|
| | Year ended December 31, 2017 | July 1, 2016 through December 31, 2016 | January 1, 2016 through June 30, 2016 | Year ended December 31, 2015 |
| | (in millions) | | (in millions) | |
| SNG | $88 | $ 56 | $ — | $ — |
| Triton | 4 | 2 | 1 | 4 |
| Horizon Pipeline | 2 | 1 | 1 | 2 |
| Atlantic Coast Pipeline | 6 | 1 | — | — |
| PennEast Pipeline | 6 | — | — | — |
| Total | $106 | $ 60 | $ 2 | $ 6 |

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SNG

In September 2016, the Company, through a wholly-owned, indirect subsidiary, acquired a 50% equity interest in SNG, which is accounted for as an equity method investment. See Note 11 under "Investment in SNG" for additional information. Selected financial information of SNG as of December 31, 2017 and 2016 and for the year ended December 31, 2017 and for the period September 1, 2016 through December 31, 2016 is as follows:

| Balance Sheet Information | As of December 31, 2017 | 2016 |
|---|---|---|
| | (in millions) | |
| Current assets | $82 | $95 |
| Property, plant, and equipment | 2,439 | 2,451 |
| Deferred charges and other assets | 121 | 129 |
| Total Assets | $2,642 | $2,675 |
| | | |
| Current liabilities | $110 | $588 |
| Long-term debt | 1,102 | 706 |
| Other deferred charges and other liabilities | 76 | 22 |
| Total Liabilities | $1,288 | $1,316 |
| | | |
| Total Stockholders' Equity | 1,354 | 1,359 |
| Total Liabilities and Stockholders' Equity | $2,642 | $2,675 |

| Income Statement Information | Year ended December 31, 2017 | September 1, 2016 through December 31, 2016 |
|---|---|---|
| | (in millions) | |
| Revenues | $544 | $ 230 |
| Operating income | 246 | 138 |
| Net income | $175 | $ 115 |

Other Investments

Triton

The Company has an investment in Triton, a cargo container leasing company, which is aggregated into its all other segment. Container equipment that is acquired by Triton is accounted for in tranches as defined in Triton's operating agreement and investors make capital contributions to Triton to invest in each of the tranches. As of December 31, 2017, the Company had invested in seven tranches established by Triton.

Horizon Pipeline

The Company owns an interest in a joint venture with Natural Gas Pipeline Company of America that is regulated by the FERC. Horizon Pipeline operates a 70-mile natural gas pipeline from Joliet, Illinois to near the Wisconsin/Illinois border. Nicor Gas typically contracts for 70% to 80% of the total annual capacity.

PennEast Pipeline

In 2014, the Company entered into a partnership in which it holds a 20% ownership interest in an interstate pipeline company formed to develop and operate a 118-mile natural gas pipeline between New Jersey and Pennsylvania. The initial transportation capacity of 1.0 billion cubic feet (Bcf) per day, is under long-term contracts, mainly by public utilities and other market-serving entities, such as electric generation companies, in New Jersey, Pennsylvania, and

New York. On January 19, 2018, the PennEast Pipeline project received FERC approval.

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Atlantic Coast Pipeline
In 2014, the Company entered into a project in which it holds a 5% ownership interest in an interstate pipeline company formed to develop and operate a 594-mile natural gas pipeline in North Carolina, Virginia, and West Virginia with initial transportation capacity of 1.5 Bcf per day. On October 13, 2017, the Atlantic Coast Pipeline project received FERC approval.
Pivotal JAX LNG, LLC
The Company owns a 50% interest in a planned LNG liquefaction and storage facility in Jacksonville, Florida. Once construction is complete and the facility is operational, it will be outfitted with a 2.0 million gallon storage tank with the capacity to produce in excess of 120,000 gallons of LNG per day.
5. INCOME TAXES
Subsequent to the Merger, Southern Company files a consolidated federal income tax return and various combined and separate state income tax returns on behalf of the Company. Under a joint consolidated income tax allocation agreement, each Southern Company subsidiary's current and deferred tax expense is computed on a stand-alone basis and no subsidiary is allocated more current expense than would be paid if it filed a separate income tax return. In accordance with IRS regulations, each company is jointly and severally liable for the federal tax liability. Prior to the Merger, the Company filed a U.S. federal consolidated income tax return and various state income tax returns.
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, the 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. The 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.
Current and Deferred Income Taxes
Details of income tax provisions are as follows:

| | Successor | | Predecessor | |
|---|---|---|---|---|
| | Year ended December 31, 2017 | July 1, 2016 through December 31, 2016 | January 1, 2016 through June 30, 2016 | Year ended December 31, 2015 |
| | (in millions) | | (in millions) | |
| Federal — | | | | |
| Current | $103 | $ — | $67 | $ (13) |
| Deferred | 170 | 65 | 8 | 198 |
| | 273 | 65 | 75 | 185 |
| State — | | | | |
| Current | 27 | (16) | 12 | 10 |
| Deferred | 67 | 27 | — | 18 |
| | 94 | 11 | 12 | 28 |

| | | | | |
|---|---|---|---|---|
| Total | $367 | $ 76 | $87 | $ 213 |

Net cash payments (refunds) for income taxes for the successor periods of the year ended December 31, 2017 and July 1, 2016 through December 31, 2016 and the predecessor periods of January 1, 2016 through June 30, 2016 and the year ended December 31, 2015 were $72 million, $23 million, $(100) million, and $(26) million, respectively.

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The tax effects of temporary differences between the carrying amounts of assets and liabilities in the financial statements and their respective tax bases, which give rise to deferred tax assets and liabilities, are as follows:

| | 2017 | 2016 |
|---|---|---|
| | (in millions) | |
| Deferred tax liabilities — | | |
| Accelerated depreciation | $1,436 | $1,954 |
| Property basis differences | 204 | 311 |
| Regulatory assets associated with employee benefit obligations | 79 | 125 |
| Other | 208 | 164 |
| Total | 1,927 | 2,554 |
| Deferred tax assets — | | |
| Federal net operating loss | 92 | 59 |
| Federal effect of state deferred taxes | 54 | 42 |
| Employee benefit obligations | 185 | 165 |
| Regulatory liability associated with the Tax Reform Legislation (not subject to normalization) | 295 | — |
| Other | 223 | 332 |
| Total | 849 | 598 |
| Less valuation allowances | (11) | (19) |
| Total, net of valuation allowances | 838 | 579 |
| Accumulated deferred income taxes, net | $1,089 | $1,975 |

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 increased tax-related regulatory liabilities.

At December 31, 2017, the tax-related regulatory liabilities to be credited to customers were $1.1 billion. These liabilities are primarily attributable to deferred taxes previously recognized at rates higher than the current enacted tax law and to unamortized ITCs.

Deferred federal and state ITCs are amortized over the average life of the related property with such amortization normally applied as a credit to reduce depreciation in the statements of income. Credits amortized in this manner amounted to $4 million and $1 million for the successor periods of the year ended December 31, 2017 and July 1, 2016 through December 31, 2016 and for the predecessor periods of January 1, 2016 through June 30, 2016 and the year ended December 31, 2015, were $1 million and $2 million, respectively. At December 31, 2017, all ITCs available to reduce federal income taxes payable had been utilized.

Effective Tax Rate

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

| | Successor | | Predecessor | |
|---|---|---|---|---|
| | Year ended December 31, 2017 | July 1, 2016 through December 31, 2016 | January 1, 2016 through June 30, 2016 | Year ended December 31, 2015 |
| Federal statutory rate | 35.0% | 35.0% | 35.0% | 35.0% |
| State income tax, net of federal deduction | 4.0 | 4.0 | 3.5 | 3.4 |
| Tax Reform Legislation | 15.0 | — | — | — |
| | 6.2 | — | — | — |

| | | | | |
|---|---|---|---|---|
| State tax legislation and rate changes | | | | |
| Other | — | 1.0 | (0.9) | (2.0) |
| Effective income tax rate | 60.2% | 40.0% | 37.6% | 36.4% |

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The principal differences in the Company's effective tax rate from December 31, 2016 to December 31, 2017 include the impact of the Tax Reform Legislation, the Illinois income tax legislation enacted in the third quarter 2017, new income tax apportionment factors in several states resulting from the Company's inclusion in the consolidated Southern Company state tax filings, the disallowance of certain nondeductible Merger-related expenses associated with change-in-control compensation charges, and an increase in earnings before income taxes.

Unrecognized Tax Benefits

The Company has no unrecognized tax benefits for any period presented.

The Company classifies interest on tax uncertainties as interest expense; however, the Company had no accrued interest or penalties for unrecognized tax benefits for any period presented.

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

On July 1, 2016, the Company became a wholly-owned subsidiary of Southern Company, which is a participant in the Compliance Assurance Process of the IRS. The IRS has finalized its audits of Southern Company's consolidated federal tax returns through 2016. However, the pre-Merger Southern Company Gas 2014, 2015, and June 30, 2016 federal tax returns are currently under audit. The audits for the Company by any state have either concluded, or the statute of limitations has expired with respect to income tax examinations, for years prior to 2011.

6. FINANCING

The Company's 100%-owned subsidiary, Southern Company Gas Capital, was established to provide for certain of the Company's ongoing financing needs through a commercial paper program, the issuance of various debt, hybrid securities, and other financing arrangements. Southern Company Gas fully and unconditionally guarantees all debt issued by Southern Company Gas Capital and the gas facility revenue bonds issued by Pivotal Utility Holdings. Additionally, substantially all of Nicor Gas' properties are subject to the lien of the indenture securing its first mortgage bonds. Nicor Gas is not permitted by regulation to make loans to affiliates or utilize Southern Company Gas Capital for its financing needs.

Securities Due Within One Year

The current portion of long-term debt is composed of the portion of its long-term debt due within the next 12 months. At December 31, 2017, the Company had $157 million of senior notes due within one year, including the fair value adjustment attributable to the application of acquisition accounting. At December 31, 2016, the Company had $22 million of medium-term notes due within one year.

Long-Term Debt

Long-term debt of the Company at December 31, 2017 and 2016 consisted of Series A, Series B, and Series C medium-term notes of Atlanta Gas Light; senior notes of Southern Company Gas Capital; first mortgage bonds of Nicor Gas; and gas facility revenue bonds of Pivotal Utility Holdings.

Maturities through 2022 applicable to total long-term debt are as follows: $155 million in 2018; $350 million in 2019; $330 million in 2021; $93 million in 2022; and $4.6 billion thereafter. There are no material scheduled maturities in 2020.

Medium-Term Notes

In July 2017, Atlanta Gas Light repaid at maturity $22 million of medium-term notes. The amount of medium-term notes outstanding at December 31, 2017 and 2016 was $159 million and $181 million, respectively, including securities due within one year.

Senior Notes

In May 2017, Southern Company Gas Capital issued $450 million aggregate principal amount of Series 2017A 4.40% Senior Notes due May 30, 2047. The proceeds were used to repay the Company's short-term indebtedness and for general corporate purposes. The amount of senior notes outstanding at December 31, 2017 and 2016 was $4.2 billion and $3.7 billion, respectively, including securities due within one year.

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First Mortgage Bonds

Nicor 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.

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.

Gas Facility Revenue Bonds

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 Pivotal Utility Holdings. 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 11 under "Proposed Sale of Elizabethtown Gas and Elkton Gas" for additional information.

Parent Company Note

On January 4, 2018, Southern Company Gas issued a floating rate promissory note to Southern Company in an aggregate principal amount of $100 million due July 31, 2018, bearing interest based on one-month LIBOR.

Dividend Restrictions

By regulation, Nicor Gas is restricted, to the extent of its retained earnings balance, in the amount it can dividend or loan to affiliates and is not permitted to make money pool loans to affiliates. The New Jersey BPU restricts the amount Elizabethtown Gas can dividend to its parent company to 70% of its quarterly net income. Additionally, as stipulated in the New Jersey BPU's order approving the Merger, the Company is prohibited from paying dividends to its parent company, Southern Company, if the Company's senior unsecured debt rating falls below investment grade. As of December 31, 2017, the amount of subsidiary retained earnings restricted for dividend payment totaled $719 million.

Bank Credit Arrangements

Credit Facilities

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

| Company | Expires 2022 | Unused |
|---|---|---|
| | (in millions) | |
| Southern Company Gas Capital | $1,400 | $1,390 |
| Nicor Gas | 500 | 500 |
| Total | $1,900 | $1,890 |

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 (Facility) currently allocated for $1.4 billion and $500 million, respectively, with a maturity date of 2022, as reflected in the table above. Pursuant to the Facility, the allocations between Southern Company Gas Capital and Nicor Gas may be adjusted.

The Facility contains a covenant that limits the ratio of debt to capitalization (as defined in each facility) to a maximum of 70% for each of the Company and Nicor Gas and contains a cross-acceleration provision to other indebtedness (including guarantee obligations) of the applicable company. Such cross-acceleration provision to other indebtedness would trigger an event of default of the applicable company if the Company or Nicor Gas defaulted on indebtedness, the payment of which was then accelerated. At December 31, 2017, both companies were in compliance with such covenant. The Facility does not contain a material adverse change clause at the time of borrowings.

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Commercial Paper Programs

The Company maintains commercial paper programs at Southern Company Gas Capital and at Nicor Gas that consist of short-term, unsecured promissory notes. Nicor Gas' commercial paper program supports working capital needs at Nicor Gas as Nicor Gas is not permitted to make money pool loans to affiliates. All of the Company's other subsidiaries benefit from Southern Company Gas Capital's commercial paper program. Commercial paper is included in notes payable in the balance sheets.

Details of commercial paper borrowings outstanding were as follows:

| | Short-term Debt at the End of the Period | | |
|---|---|---|---|
| | Amount Outstanding | Weighted Average Interest Rate | |
| | (in millions) | | |
| December 31, 2017: | | | |
| Southern Company Gas Capital | $1,243 | 1.73 | % |
| Nicor Gas | 275 | 1.83 | |
| Total | $1,518 | 1.75 | % |
| | | | |
| December 31, 2016: | | | |
| Southern Company Gas Capital | $733 | 1.09 | % |
| Nicor Gas | 524 | 0.95 | |
| Total | $1,257 | 1.03 | % |

7. COMMITMENTS

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 and demand charges associated with Sequent. The gas supply balance includes amounts for Nicor Gas' and SouthStar's gas commodity purchase commitments of 35 million mmBtu at floating gas prices calculated using forward natural gas prices at December 31, 2017 and valued at $101 million. The Company 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:

| | Pipeline Charges, Storage Capacity, and Gas Supply |
|---|---|
| | (in millions) |
| 2018 | $ 813 |
| 2019 | 552 |
| 2020 | 416 |

| | |
|---|---|
| 2021 | 375 |
| 2022 | 339 |
| 2023 and thereafter | 2,294 |
| Total | $ 4,789 |

Operating Leases

The Company has operating lease agreements with various terms and expiration dates. Total rent expense was $15 million, $8 million, $6 million, and $12 million for the successor periods of the year ended December 31, 2017 and July 1, 2016 through December 31, 2016 and the predecessor periods of January 1, 2016 through June 30, 2016 and the year ended December 31, 2015, respectively. The Company includes any step rents, escalations, and lease concessions in its computation of minimum lease payments, which are recognized on a straight-line basis over the minimum lease terms.

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

| | Minimum Lease Payments (in millions) |
|---|---|
| 2018 | $ 17 |
| 2019 | 16 |
| 2020 | 16 |
| 2021 | 15 |
| 2022 | 13 |
| 2023 and thereafter | 26 |
| Total | $ 103 |

Financial Guarantees

AGL Equipment Leasing Inc. (AEL), a wholly-owned subsidiary of the Company, holds the Company's interest in Triton and has an obligation to restore to zero any deficit in its equity account for income tax purposes in the unlikely event that Triton is liquidated and a deficit balance remains. This obligation continues for the life of the Triton partnerships. Any payment is effectively limited to the net assets of AEL, which were less than $1 million at December 31, 2017. The Company believes the likelihood of any such payment by AEL is remote and, as such, no liability has been recorded for this obligation at December 31, 2017.

8. STOCK COMPENSATION

Successor

Stock-Based Compensation

Stock-based compensation primarily in the form of Southern Company performance share units and restricted stock units may be granted through the Omnibus Incentive Compensation Plan to certain levels of management within the Company. In 2017, stock-based compensation granted to employees includes performance share units and restricted stock units. In 2016, in conjunction with the Merger, stock-based compensation was granted to certain executives in the form of Southern Company restricted stock and performance share units. As of December 31, 2017, there were 327 current and former employees participating in the performance share unit and restricted stock unit programs.

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.

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

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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.

For the year ended December 31, 2017, employees of the Company were granted 0.3 million performance share units. The weighted average grant-date fair value of TSR-based performance share units granted during 2017, determined using a Monte Carlo simulation model to estimate the TSR of Southern Company's stock among the industry peers over the performance period, was $49.27. The weighted average grant-date fair value of both EPS-based and ROE-based performance share units granted during 2017 was $49.22.

For the year ended December 31, 2017, total compensation cost for performance share units recognized in income was $8 million with the related tax benefit also recognized in income of $3 million. The compensation cost related to the grant of Southern Company performance share units to the Company's employees is recognized in the Company's financial statements with a corresponding credit to equity, representing a capital contribution from Southern Company. As of December 31, 2017, $6 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

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.

For the year ended December 31, 2017, employees of the Company were granted 0.1 million restricted stock units. The weighted average grant-date fair value of restricted stock units granted during 2017 was $49.23.

For the year ended December 31, 2017, total compensation cost for restricted stock units recognized in income was $4 million with the related tax benefit also recognized in income of $2 million. The compensation cost related to the grant of Southern Company restricted stock units to the Company's employees is recognized in the Company's financial statements with a corresponding credit to equity, representing a capital contribution from Southern Company. As of December 31, 2017, $1 million of total unrecognized compensation cost related to restricted stock units will be recognized over a weighted-average period of approximately 13 months.

Merger Stock Compensation

At the effective time of the Merger, each share of Southern Company Gas common stock, other than certain excluded shares, was converted into the right to receive $66 in cash, without interest. Also at the effective time of the Merger:

- Southern Company Gas' outstanding restricted stock units, restricted stock awards, and non-employee director stock awards were deemed fully vested and were canceled and converted into the right to receive an amount in cash equal to the product of (i) the total number of shares of Southern Company Gas' common stock subject to such award and (ii) the Merger consideration of $66 per share;

- Southern Company Gas' outstanding stock options, all of which were fully vested, were canceled and converted into the right to receive an amount in cash equal to the product of (i) the total number of shares of Southern Company Gas' common stock subject to such options and (ii) the excess of the Merger consideration of $66 per share over the applicable exercise price per share of such options; and
- each outstanding award of a performance share unit was converted into an award of Southern Company's restricted stock units (restricted stock awards).

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In conjunction with the Merger, stock-based compensation, in the form of Southern Company restricted stock and performance share units, was granted to certain executives of the Company through the Southern Company Omnibus Incentive Compensation Plan.

Southern Company Restricted Stock Awards

Under the terms of the restricted stock awards, the employees received a specified number of restricted stock units that vest when the employees have satisfied the requisite service period(s) at which time the employee receives Southern Company common stock. The terms of the award require the employee to be continuously employed through the original three-year vesting schedule of the award being replaced.

For the successor period ended December 31, 2016, employees of the Company were granted 0.7 million restricted stock units. The grant-date fair value of the restricted stock units granted was $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. The remaining fair value of $12 million is being recognized as compensation expense on a straight-line basis over the remaining vesting period.

The compensation cost related to the grant of restricted stock units to the Company's employees are recognized in the Company's financial statements with a corresponding credit to equity, representing a capital contribution from Southern Company. For the successor year ended December 31, 2017 and the successor period of July 1, 2016 through December 31, 2016, total compensation cost for restricted stock units recognized in income was $8 million and $13 million, respectively, with the related tax benefit also recognized in income of $4 million and $4 million, respectively. 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. See "Performance Share Unit Awards" herein for additional information.

Change in Control Awards

Southern Company awarded performance share units to certain employees remaining with the 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 the Company, or any of its affiliates, 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 with the number of shares issued ranging from 0% to 100% of the target number of performance share units granted, based on achievement of certain Southern Company common stock price metrics, as well as 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 successor year ended December 31, 2017 and the successor period of July 1, 2016 through December 31, 2016, total compensation cost for the change-in-control awards recognized in income was $12 million and $4 million, respectively, with $6 million and less than $1 million, respectively, of related tax benefit recognized in income. The compensation cost related to the grant of Southern Company change-in-control benefit and achievement shares to the Company's employees are recognized in the Company's financial statements with a corresponding credit to a liability or equity, representing a capital contribution from Southern Company, respectively. As of December 31, 2017, $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.

Predecessor

For the predecessor periods of January 1, 2016 through June 30, 2016 and the year ended December 31, 2015, the employees of Southern Company Gas and subsidiaries participated in the AGL Resources Inc. Omnibus Performance Incentive Plan, as amended and restated.

The AGL Resources Inc. Omnibus Performance Incentive Plan, as amended and restated, and the Long-Term Incentive Plan (1999) provided for the grant of incentive and nonqualified stock options, stock appreciation rights, shares of restricted stock, restricted stock units, performance cash awards, and other stock-based awards to officers and key employees. Effective July 1, 2016, all Southern Company Gas shares of stock were canceled and/or converted as a result of the Merger. No further grants will be made from the Long-Term Incentive Plan (1999) or the AGL Resources Inc. Omnibus Performance Incentive Plan, as amended and restated.

For the predecessor periods, the Company recognized stock-based compensation expense for its stock-based awards over the requisite service period based on the estimated fair value at the date of grant for its stock-based awards using the modified prospective method. These stock awards included: stock options, stock and restricted stock awards, and performance units (restricted stock units, performance share units, and performance cash units).

Performance-based stock awards and performance units contained market and performance conditions. Stock options, restricted stock awards, and performance units also contained a service condition. The Company estimated forfeitures over the requisite service period when recognizing compensation expense. These estimates were adjusted to the extent that actual forfeitures differ, or were expected to materially differ, from such estimates. Excess tax benefits were reported as a financing cash inflow. The difference between the proceeds from the exercise of the Company's stock-based awards and the par value of the stock was recorded within additional paid-in capital.

Southern Company Gas granted stock awards with a grant price that was equal to the fair market value on the date of the grant. Fair market value was defined under the terms of the applicable plans as the closing price per share of Southern Company Gas' common stock on the grant date. For the predecessor periods of January 1, 2016 through June 30, 2016 and the year ended December 31, 2015, total compensation cost for cash and stock-based awards recognized in income was $24 million and $40 million, respectively, with related tax benefits also recognized in income, which were immaterial.

Incentive and Nonqualified Stock Options

The stock options that the Company granted prior to the Merger had a three-year vesting period and expired ten years after the date of grant. The exercise price for stock options granted equaled the stock price of Southern Company Gas common stock on the date of grant. Participants realized value from option grants only to the extent that the fair market value of the Company's common stock on the date of exercise of the option exceeded the fair market value of the common stock on the date of the grant. No stock options have been issued under the plan since 2009.

The Company measured compensation cost related to stock options based on the fair value of these awards at their date of grant using the Black-Scholes option-pricing model. For the predecessor year ended December 31, 2015, the Company had no unrecognized compensation costs related to stock options. For the predecessor period ended June 30, 2016 and the year ended December 31, 2015, cash received from stock option exercises and the related income tax benefits were immaterial.

For the predecessor periods of January 1, 2016 through June 30, 2016 and the year ended December 31, 2015, the total intrinsic value of options exercised was $3 million, and $13 million, respectively.

Effective July 1, 2016, all of the Company's outstanding stock options, all of which were fully vested, were canceled and converted into the right to receive an amount in cash equal to the product of (i) the total number of shares of Southern Company Gas' common stock subject to such options and (ii) the excess of the Merger consideration of $66 per share over the applicable exercise price per share of such options.

Restricted Stock Units

A restricted stock unit is an award that represents the opportunity to receive a specified number of shares of the Company's common stock, subject to the achievement of certain pre-established performance criteria. For the predecessor period of January 1, 2016 through June 30, 2016 and the year ended December 31, 2015, the Company granted 25,166 and 47,546, respectively, of restricted stock units (including dividends) to certain employees. At the effective time of the Merger, all restricted stock units outstanding were deemed fully vested and were canceled and converted into the right to receive an amount in cash equal to the product of (i) the total number of shares of Southern Company Gas' common stock subject to such award and (ii) the Merger consideration of $66 per share.

Performance Share Unit Awards

A performance share unit award represented the opportunity to receive cash and shares subject to the achievement of certain pre-established performance criteria. For the predecessor periods of January 1, 2016 through June 30, 2016 and the year ended December 31, 2015, the Company granted performance share unit awards to certain officers. The Company's 2016 and 2015 performance share units had two performance measures. One measure, which accounted for 75%, related to the Company's total shareholder return relative to a group of peer companies. The second measure, which accounted for 25%, related to the Company's earnings per share, excluding wholesale gas services, over the three-year performance period.

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At the effective time of the Merger, each outstanding performance share unit was converted into an award of Southern Company's restricted stock units. The conversion ratio was the product of (i) the greater of (a) 125% of the number of units underlying such award based on target level achievement of all relevant performance goals and (b) the number of units underlying such award based on the actual level of achievement of all relevant performance goals against target and (ii) an exchange ratio based on the Merger consideration of $66 per share as compared to the volume-weighted average price per share of Southern Company common stock. The resulting Southern Company restricted stock units will follow the vesting schedule and payment terms, and otherwise be issued on similar terms and conditions, as were applicable to such pre-Merger performance share unit awards, subject to certain exceptions. See "Southern Company Restricted Stock Awards" for additional information.

Stock and Restricted Stock Awards

The compensation cost of both stock awards and restricted stock awards was equal to the grant date fair value of the awards, recognized over the requisite service period. No other assumptions were used to value the awards. The Company referred to restricted stock as an award of Company common stock subject to time-based vesting or achievement of performance measures. Prior to vesting, restricted stock awards were subject to certain transfer restrictions and forfeiture upon termination of employment.

Restricted Stock Awards — Employees

Total unvested restricted stock awards outstanding as of December 31, 2015 totaled 0.4 million. During 2016, 0.3 million restricted stock awards were granted, 0.7 million restricted stock awards were vested or forfeited. At the effective time of the Merger, Southern Company Gas' outstanding restricted stock awards were deemed fully vested and were canceled and converted into the right to receive an amount in cash equal to the product of (i) the total number of shares of Southern Company Gas' common stock subject to such award and (ii) the Merger consideration of $66 per share.

9. FAIR VALUE MEASUREMENTS

Fair value measurements are based on inputs of observable and unobservable market data that a market participant would use in pricing the asset or liability. The use of observable inputs is maximized where available and the use of unobservable inputs is minimized for fair value measurement and reflects a three-tier fair value hierarchy that prioritizes inputs to valuation techniques used for fair value measurement. See Note 1 under "Fair Value Measurements" for additional information on the fair value hierarchy.

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 | $ 223 | $ — | $ — | $554 |
| Liabilities: | | | | | |

| | | | | | |
|---|---|---|---|---|---|
| Energy-related derivatives[a][b] | $479 | $ 181 | $ — | $ — | $660 |

(a) Energy-related derivatives excludes $11 million associated with premiums and certain weather derivatives accounted for based on intrinsic value rather than fair value.
(b) Energy-related derivatives excludes cash collateral of $193 million.

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As of December 31, 2016, assets and liabilities measured at fair value on a recurring basis during the period, together with their associated level of the fair value hierarchy, were as follows:

| | 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 | $ 239 | $ — | $ — | $577 |
| Liabilities: | | | | | |
| Energy-related derivatives[(a)(b)] | $345 | $ 224 | $ — | $ — | $569 |

(a) Energy-related derivatives excludes $4 million associated with certain weather derivatives accounted for based on intrinsic value rather than fair value.
(b) Energy-related derivatives excludes cash collateral of $62 million.

Valuation Methodologies

The energy-related derivatives primarily consist of exchange-traded financial products for natural gas, 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, implied volatility, and overnight index swap interest rates. Interest rate derivatives are also standard OTC products that are valued using observable market data and assumptions commonly used by market participants. See Note 10 for additional information on how these derivatives are used.

Debt

The Company's long-term debt is recorded at amortized cost, including the fair value adjustments at the effective date of the Merger. The Company amortizes the fair value adjustments over the lives of the respective bonds. The following table presents the carrying amount and fair value of the Company's long-term debt as of December 31:

| | Carrying Amount | Fair Value |
|---|---|---|
| | (in millions) | |
| Long-term debt, including securities due within one year: | | |
| 2017 | $6,048 | $6,471 |
| 2016 | $5,281 | $5,491 |

The fair values are determined using Level 2 measurements and are based on quoted market prices for the same or similar issues or on the current rates available to the Company.

10. DERIVATIVES

The Company is exposed to market risks, primarily commodity price risk, interest rate risk, and weather risk. To manage the volatility attributable to these exposures, the Company nets its exposures, where possible, to take advantage of natural offsets and enters into various derivative transactions for the remaining exposures pursuant to the Company's policies in areas such as counterparty exposure and risk management practices. Wholesale gas operations use various contracts in its commercial activities that generally meet the definition of derivatives. For other businesses, the Company's policy is that derivatives are to be used primarily for hedging purposes. In both cases, the Company mandates strict adherence to all applicable risk management policies. Derivative positions are monitored using techniques including, but not limited to, market valuation, value at risk, stress testing, and sensitivity analysis. Derivative instruments are recognized at fair value in the balance sheets as either assets or liabilities and are presented on a net basis. See Note 9 for additional information. In the statements of cash flows, the cash impacts of settled energy-related and interest rate derivatives are recorded as operating activities.

Energy-Related Derivatives

The Company enters into energy-related derivatives to hedge exposures to natural gas price changes. However, due to cost-based rate regulations and other various cost recovery mechanisms, gas distribution operations has limited exposure to market volatility in prices of natural gas. The Company manages fuel-hedging programs, implemented per the guidelines of the natural gas

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distribution utilities' respective state regulatory agencies, through the use of financial derivative contracts, which is expected to continue to mitigate price volatility. However, the Company retains exposure to price changes that can, in a volatile energy market, be extremely material and can adversely affect the Company.

The Company 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 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 the cost of natural gas as the underlying natural gas is used in operations and ultimately recovered through the respective 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 other 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 in the period of change.

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 natural gas industry. When an energy-related derivative contract is settled physically, any cumulative unrealized gain or loss is reversed and the contract price is recognized in the respective line item representing the actual price of the underlying goods being delivered.

At December 31, 2017, the net volume of energy-related derivative contracts for natural gas positions totaled 300 million mmBtu for the Company, together with the longest hedge date of 2020 over which the Company 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.

For cash flow hedges, the estimated pre-tax losses that will be reclassified from accumulated OCI to earnings for the 12-month period ending December 31, 2018 are $4 million.

Interest Rate Derivatives

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

In 2015, the Company executed $800 million in notional value of 10-year and 30-year fixed-rate forward-starting interest rate swaps to hedge potential interest rate volatility designated as cash flow hedges of issuances of long-term debt in the fourth quarter 2015 and during 2016. The Company settled $200 million of these interest rate swaps in 2015 for an immaterial loss, $400 million in May 2016 at a loss of $26 million, and the remaining $200 million in September 2016 at a loss of $35 million. Due to the application of acquisition accounting, only $5 million of the pre-tax loss incurred and deferred in the successor period is being amortized to interest expense through 2046.

Derivative Financial Statement Presentation and Amounts

The derivative contracts of the Company are subject to master netting arrangements or similar agreements and are reported net in the financial statements. Some of these energy-related and interest rate derivative contracts may contain certain provisions that permit intra-contract netting of derivative receivables and payables for routine billing and offsets related to events of default and settlements.

At December 31, 2017 and 2016, the fair value of energy-related derivatives and interest rate derivatives was reflected in the balance sheets as follows:

| Derivative Category and Balance Sheet Location | 2017 Assets | 2017 Liabilities | 2016 Assets | 2016 Liabilities |
|---|---|---|---|---|
| | (in millions) | | (in millions) | |
| Derivatives designated as hedging instruments for regulatory purposes | | | | |
| Energy-related derivatives: | | | | |
| Assets from risk management activities/Liabilities from risk management activities-current | $5 | $ 8 | $24 | $ 3 |
| Other deferred charges and assets/Other deferred credits and liabilities | — | — | 1 | — |
| Total derivatives designated as hedging instruments for regulatory purposes | $5 | $ 8 | $25 | $ 3 |
| Derivatives designated as hedging instruments in cash flow and fair value hedges | | | | |
| Energy-related derivatives: | | | | |
| Assets from risk management activities/Liabilities from risk management activities-current | $— | $ 3 | $4 | $ 3 |
| Derivatives not designated as hedging instruments | | | | |
| Energy-related derivatives: | | | | |
| Assets from risk management activities/Liabilities from risk management activities-current | $379 | $ 434 | $486 | $ 482 |
| Other deferred charges and assets/Other deferred credits and liabilities | 170 | 215 | 66 | 81 |
| Total derivatives not designated as hedging instruments | $549 | $ 649 | $552 | $ 563 |
| Gross amounts recognized | $554 | $ 660 | $581 | $ 569 |
| Gross amounts offset[(a)] | $(390) | $ (583) | $(435) | $ (497) |
| Net amounts recognized in the Balance Sheets [(b)] | $164 | $ 77 | $146 | $ 72 |

(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 amount of derivative instruments outstanding excludes 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 effect of unrealized derivative gains (losses) arising from energy-related derivatives designated as regulatory hedging instruments and deferred were as follows:

| Derivative Category | Balance Sheet Location | Unrealized Losses 2017 | Unrealized Losses 2016 | Balance Sheet Location | Unrealized Gains 2017 | Unrealized Gains 2016 |
|---|---|---|---|---|---|---|
| | | (in millions) | | | (in millions) | |
| Energy-related derivatives: | | | | | | |
| | Other regulatory assets, current | $ (4) | $ (1) | Other regulatory liabilities, current | $ 7 | $ 17 |
| | Other regulatory assets, deferred | — | — | Other regulatory liabilities, deferred | — | 1 |
| Total energy-related derivative gains (losses)[(*)] | | $ (4) | $ (1) | | $ 7 | $ 18 |

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

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For all periods presented, the pre-tax effect of energy-related derivatives and interest rate derivatives designated as cash flow hedging instruments recognized in OCI and those reclassified from accumulated OCI into earnings were as follows:

| Derivatives in Cash Flow Hedging Relationships | Gain (Loss) Recognized in OCI on Derivative (Effective Portion) Successor 2017 (in millions) | Statements of Income Location | Gain (Loss) Reclassified from Accumulated OCI into Income (Effective Portion) Successor 2017 (in millions) |
|---|---|---|---|
| Energy-related derivatives | $ (9 ) | Cost of natural gas | $ (2 ) |

| Derivatives in Cash Flow Hedging Relationships | Gain (Loss) Recognized in OCI on Derivative (Effective Portion) Successor July 1, 2016 through December 31, 2016 (in millions) | Predecessor January 1, 2016 through June 30, 2016 (in millions) | Statements of Income Location | Gain (Loss) Reclassified from Accumulated OCI into Income (Effective Portion) Successor July 1, 2016 through December 31, 2016 (in millions) | Predecessor January 1, 2016 through June 30, 2016 (in millions) |
|---|---|---|---|---|---|
| Energy-related derivatives | $2 | $ — | Cost of natural gas | $ (1 ) | $ (1 ) |
| Interest rate derivatives | (5 ) | (64 ) | Interest expense, net of amounts capitalized | — | — |
| Total derivatives in cash flow hedging relationships | $ (3) | $ (64 ) | | $ (1 ) | $ (1 ) |

| | Gain (Loss) Recognized in OCI on Derivative (Effective Portion) Predecessor | | Gain (Loss) Reclassified from Accumulated OCI into Income (Effective Portion) Predecessor |
|---|---|---|---|

| Derivatives in Cash Flow Hedging Relationships | 2015 (in millions) | Statements of Income Location | 2015 (in millions) |
|---|---|---|---|
| Energy-related derivatives | $ 3 | Cost of natural gas | $ (10) |
| | | Other operations and maintenance | (1) |
| Interest rate derivatives | — | Interest expense, net of amounts capitalized | 2 |
| Total derivatives in cash flow hedging relationships | $ 3 | | $ (9) |

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

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For all periods presented, the pre-tax effects of energy-related derivatives not designated as hedging instruments on the statements of income were as follows:

| Derivatives in Non-Designated Hedging Relationships | Statements of Income Location | Gain (Loss) Successor Year Ended December 31, 2017 | Successor July 1, 2016 through December 31, 2016 | Predecessor January 1, 2016 through June 30, 2016 | Predecessor Year Ended December 31, 2015 |
|---|---|---|---|---|---|
| | | (in millions) | | (in millions) | |
| Energy-related derivatives | Natural gas revenues(*) | $ (80) | $ 33 | $ (1) | $ 56 |
| | Cost of natural gas | (2) | 3 | (62) | (6) |
| Total derivatives in non-designated hedging relationships | | $ (82) | $ 36 | $ (63) | $ 50 |

(*) Excludes the impact of weather derivatives recorded in natural gas revenues of $23 million for the successor year ended December 31, 2017, $6 million for the successor period of July 1, 2016 through December 31, 2016, $3 million for the predecessor period of January 1, 2016 through June 30, 2016, and $12 million for the predecessor year ended December 31, 2015.

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 a credit rating change below BBB- and/or Baa3. 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 derivative liabilities with contingent features was $3 million and the maximum potential collateral requirements arising from the credit-risk-related contingent features, at a rating below BBB- and/or Baa3, was $2 million.

Generally, collateral may be provided by a guaranty, letter of credit, or cash. If collateral is required, fair value amounts recognized for the right to reclaim cash collateral or the obligation to return cash collateral are not offset against fair value amounts recognized for derivatives executed with the same counterparty.

The Company is exposed to losses related to financial instruments in the event of counterparties' nonperformance. The Company has established risk management policies and controls to determine and monitor the creditworthiness of counterparties in order to mitigate the Company's exposure to counterparty credit risk. Prior to entering into a physical transaction, the Company assigns physical wholesale counterparties an internal credit rating and credit limit based on the counterparties' Moody's, S&P, and Fitch ratings, commercially available credit reports, and audited financial statements. The Company may require counterparties to pledge additional collateral when deemed necessary. Credit evaluations are conducted and appropriate internal approvals are obtained for a 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, the Company requires credit enhancements by way of a guaranty, cash deposit, or letter of credit for transaction counterparties that do not have investment grade ratings.

The Company also utilizes master netting agreements whenever possible to mitigate exposure to counterparty credit risk. When the Company 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 the Company's credit risk. The Company also uses other netting agreements with certain counterparties with whom it conducts significant transactions. Master netting agreements enable the Company to net certain assets and liabilities by counterparty. The Company also nets across product lines and against cash collateral, provided the master netting and cash collateral agreements include such provisions. The Company may require counterparties to pledge additional collateral when deemed necessary. Therefore, the Company does not anticipate a material adverse effect on the financial statements as a result of counterparty nonperformance.

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11. MERGER, ACQUISITION, AND DISPOSITIONS
Merger with Southern Company
On July 1, 2016, the Company completed the Merger with Southern Company. A wholly-owned, direct subsidiary of Southern Company merged with and into Southern Company Gas, with the Company surviving as a wholly-owned, direct subsidiary of Southern Company.
At the effective time of the Merger, each share of Southern Company Gas common stock, other than certain excluded shares, was converted into the right to receive $66 in cash, without interest. Also at the effective time of the Merger, all of the outstanding restricted stock units, restricted stock awards, non-employee director stock awards, stock options, and performance share units were either redeemed or converted into Southern Company's restricted stock units. See Note 8 for additional information.
The application of the acquisition method of accounting was pushed down to the Company. The excess of the purchase price over the fair values of the Company's assets and liabilities was recorded as goodwill, which represents a different basis of accounting from the historical basis prior to the Merger. The following table presents the final purchase price allocation:

| | Successor New Basis | Predecessor Old Basis | Change in Basis |
|---|---|---|---|
| | (in millions) | (in millions) | |
| Current assets | $ 1,557 | $ 1,474 | $ 83 |
| Property, plant, and equipment | 10,108 | 10,148 | (40) |
| Goodwill | 5,967 | 1,813 | 4,154 |
| Other intangible assets | 400 | 101 | 299 |
| Regulatory assets | 1,118 | 679 | 439 |
| Other assets | 229 | 273 | (44) |
| Current liabilities | (2,201) | (2,205) | 4 |
| Other liabilities | (4,742) | (4,600) | (142) |
| Long-term debt | (4,261) | (3,709) | (552) |
| Contingently redeemable noncontrolling interest | (174) | (41) | (133) |
| Total purchase price/equity | $ 8,001 | $ 3,933 | $ 4,068 |

Measurement period adjustments were recorded to the purchase price allocation during the fourth quarter 2016, which resulted in a net $30 million increase in goodwill to establish intangible liabilities for transportation contracts at wholesale services, partially offset by adjustments to deferred tax balances.
In determining the fair value of assets and liabilities subject to rate regulation that allows recovery of costs and/or a fair return on investments, historical cost was deemed to be a reasonable proxy for fair value, as it is included in rate base or otherwise specified in regulatory recovery mechanisms. Property, plant, and equipment subject to rate regulation was reflected based on the historical gross amount of assets in service and accumulated depreciation, as they are included in rate base. For certain assets and liabilities subject to rate regulation (such as debt instruments and employee benefit obligations), the fair value adjustment was applied to historical cost with a corresponding offset to regulatory asset or liability based on the assessment of probable future recovery in rates.
For unregulated assets and liabilities, fair value adjustments were applied to historical cost of natural gas for sale, property, plant, and equipment, debt instruments, and noncontrolling interest. The valuation of other intangible assets included customer relationships, trade names, and favorable/unfavorable contracts. The valuation of these assets and liabilities applied either the market approach or income approach. The market approach was utilized when prices and other relevant market information were available. The income approach, which is based on discounted cash flows, was

primarily based on significant unobservable inputs (Level 3). Key estimates and inputs included forecasted profitability and cash flows, customer retention rates, royalty rates, and discount rates.

The estimated fair value of deferred income taxes was determined by applying the appropriate enacted statutory tax rate to the temporary differences that arose on the differences between the financial reporting value and tax basis of the assets acquired and liabilities assumed.

NOTES (continued)
Southern Company Gas and Subsidiary Companies 2017 Annual Report

The excess of the purchase price over the estimated fair value of assets and liabilities of $6 billion was recognized as goodwill, which is primarily attributable to positioning Southern Company to provide natural gas infrastructure to meet customers' growing energy needs and to compete for growth across the energy value chain. The Company anticipates that the majority of the value assigned to goodwill will not be deductible for tax purposes.
The receipt of required regulatory approvals was conditioned upon certain terms and commitments. In connection with these regulatory approvals, certain regulatory agencies prohibited the Company from recovering goodwill and Merger-related expenses, required the Company to maintain a minimum number of employees for a set period of time to ensure that certain pipeline safety standards and the competence level of the employee workforce is not degraded, and/or required the Company to maintain its pre-Merger level of support for various social and charitable programs. The most notable terms and commitments with potential financial impacts included:

- rate credits of $18 million to be paid to customers in New Jersey and Maryland;
- sharing of Merger savings with customers in Georgia starting in 2020;
- phasing-out the use of the Nicor name or logo by certain of the Company's gas marketing services subsidiaries in conducting non-utility business in Illinois;
- reaffirming that Elizabethtown Gas would file a base rate case no later than September 1, 2016, with another base rate case no later than three years after the 2016 rate case; and
- requiring Elkton Gas to file a base rate case within two years of closing the Merger.

There is no restriction on the Company's other utilities' ability to file future rate cases. The rate credits to customers in New Jersey and Maryland were paid during the third and fourth quarters of 2016, respectively. The use of the Nicor name and logo was phased out, effective November 1, 2017, by certain of the Company's gas marketing services subsidiaries in conducting non-utility business in Illinois. Elizabethtown Gas filed a base rate case with the New Jersey BPU on September 1, 2016. See Note 3 under "Base Rate Cases" for additional information. Upon completion of the Merger, the Company amended and restated its Bylaws and Articles of Incorporation, under which it now has the authority to issue no more than 110 million shares of stock consisting of (i) 100 million shares of common stock and (ii) 10 million shares of preferred stock, both categories of which have a par value of $0.01 per share. The amended and restated Articles of Incorporation do not allow any treasury shares to be held.
Investment in SNG
In September 2016, the Company, through a wholly-owned, indirect subsidiary, acquired a 50% equity interest in SNG pursuant to a definitive agreement between Southern Company and Kinder Morgan, Inc. in July 2016, to which Southern Company assigned all rights and obligations to the Company in August 2016. SNG owns 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 $1.4 billion was financed by a $1.05 billion equity contribution from Southern Company and $360 million of cash paid by the Company, which was financed by a promissory note from Southern Company repaid with a portion of the proceeds from senior notes issued in September 2016. The purchase price of the 50% equity interest exceeded the underlying ownership interest in the net assets of SNG by approximately $700 million. This basis difference is attributable to goodwill and deferred tax assets. While the deferred tax assets will be amortized through deferred tax expense, the goodwill will not be amortized and is not required to be tested for impairment on an annual basis. The Company's investment in SNG decreased by $104 million related to the impact of the Tax Reform Legislation and new income tax apportionment factors in several states resulting from the Company's inclusion in the consolidated Southern Company state tax filings.
On March 31, 2017, the Company made an additional $50 million contribution to maintain its 50% equity interest in SNG. See Note 4 under "Equity Method Investments" for additional information on this investment.
Proposed Sale of Elizabethtown Gas and Elkton Gas

On October 15, 2017, the Company's 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. The Company 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.

12. SEGMENT AND RELATED INFORMATION

The Company manages its business through four reportable segments - gas distribution operations, gas marketing services, wholesale gas services, and gas midstream operations. The non-reportable segments are combined and presented as all other. In conjunction with the Merger, the Company changed the names of certain reportable segments to better align with its new parent company.

Gas distribution operations is the largest component of the Company's business and includes natural gas local distribution utilities that construct, manage, and maintain intrastate natural gas pipelines and gas distribution facilities in seven states. Gas marketing services includes natural gas marketing to end-use customers primarily in Georgia and Illinois. Additionally, gas marketing services provides home equipment protection products and services. Wholesale gas services provides natural gas asset management and/or related logistics services for each of the Company's utilities except Nicor Gas as well as for non-affiliated companies. Additionally, wholesale gas services segment engages in natural gas storage and gas pipeline arbitrage and related activities. Since the acquisition of the Company's 50% interest in SNG, gas midstream operations primarily consists of the Company's gas pipeline investments, with storage and fuel operations also aggregated into this segment. The all other column includes segments below the quantitative threshold for separate disclosure, including the subsidiaries that fall below the quantitative threshold for separate disclosure.

After the Merger, the Company changed the segment performance measure to net income, which is utilized by its parent company. In order to properly assess net income by segment, the Company executed various intercompany note agreements to revise interest charges to its segments. Since such agreements did not exist in the predecessor periods, the Company is unable to provide the comparable net income for those periods.

NOTES (continued)
Southern Company Gas and Subsidiary Companies 2017 Annual Report

Financial data for business segments for the successor year ended December 31, 2017, the successor period of July 1, 2016 through December 31, 2016, and the predecessor periods of January 1, 2016 through June 30, 2016 and the year ended December 31, 2015 were as follows:

| | Gas Distribution Operations | Gas Marketing Services | Wholesale Gas Services[(a)] | Gas Midstream Operations | Total | All Other | Eliminations | Consolidated |
|---|---|---|---|---|---|---|---|---|
| | (in millions) | | | | | | | |
| Successor – Year ended December 31, 2017 | | | | | | | | |
| Operating revenues | $3,207 | $ 860 | $ 6 | $ 71 | $4,144 | $ 10 | $ (234) | $ 3,920 |
| Depreciation and amortization | 391 | 62 | 2 | 18 | 473 | 28 | — | 501 |
| Operating income (loss) | 650 | 113 | (51) | (10) | 702 | (37) | — | 665 |
| Earnings from equity method investments | — | — | — | 103 | 103 | 3 | — | 106 |
| Interest expense | (153) | (5) | (7) | (33) | (198) | (2) | — | (200) |
| Income taxes[(b)] | 178 | 24 | — | 61 | 263 | 104 | — | 367 |
| Segment net income (loss)[(b)] | 353 | 84 | (57) | 3 | 383 | (140) | — | 243 |
| Gross property additions | 1,330 | 9 | 1 | 134 | 1,474 | 34 | — | 1,508 |
| Successor – Total assets at December 31, 2017 | 19,358 | 2,147 | 1,096 | 2,241 | 24,842 | 12,184 | (14,039) | 22,987 |
| Successor – July 1, 2016 through December 31, 2016 | | | | | | | | |
| Operating revenues | $1,342 | $ 354 | $ 24 | $ 31 | $1,751 | $ 3 | $ (102) | $ 1,652 |
| Depreciation and amortization | 185 | 35 | 1 | 9 | 230 | 8 | — | 238 |
| Operating income (loss) | 222 | 27 | (2) | (7) | 240 | (43) | — | 197 |
| Earnings from equity method investments | — | — | — | 58 | 58 | 2 | — | 60 |
| Interest expense | (105) | (1) | (3) | (16) | (125) | 44 | — | (81) |
| Income taxes | 51 | 7 | (3) | 16 | 71 | 5 | — | 76 |
| Segment net income (loss) | 77 | 19 | — | 20 | 116 | (2) | — | 114 |
| Gross property additions | 561 | 5 | 1 | 54 | 621 | 11 | — | 632 |
| Successor – Total assets at December 31, 2016 | 19,453 | 2,084 | 1,127 | 2,211 | 24,875 | 11,145 | (14,167) | 21,853 |

NOTES (continued)
Southern Company Gas and Subsidiary Companies 2017 Annual Report

| | Gas Distribution Operations | Gas Marketing Services | Wholesale Gas Services[(a)] | Gas Midstream Operations | Total | All Other | Eliminations | Consolidated |
|---|---|---|---|---|---|---|---|---|
| | (in millions) | | | | | | | |
| Predecessor – January 1, 2016 through June 30, 2016 | | | | | | | | |
| Operating revenues | $1,575 | $ 435 | $ (32) | $ 25 | $2,003 | $ 4 | $ (102) | $ 1,905 |
| Depreciation and amortization | 178 | 11 | 1 | 9 | 199 | 7 | — | 206 |
| Operating income (loss) | 351 | 109 | (69) | (9) | 382 | (61) | — | 321 |
| EBIT | 353 | 109 | (68) | (6) | 388 | (60) | — | 328 |
| Gross property additions | 484 | 4 | 1 | 43 | 532 | 16 | — | 548 |
| Predecessor – Year Ended December 31, 2015 | | | | | | | | |
| Operating revenues | $3,049 | $ 835 | $ 202 | $ 55 | $4,141 | $ 11 | $ (211) | $ 3,941 |
| Depreciation and amortization | 336 | 25 | 1 | 18 | 380 | 17 | — | 397 |
| Operating income (loss) | 571 | 152 | 112 | (26) | 809 | (63) | — | 746 |
| EBIT | 581 | 152 | 110 | (23) | 820 | (59) | — | 761 |
| Gross property additions | 957 | 7 | 2 | 27 | 993 | 34 | — | 1,027 |
| Predecessor – Total assets at December 31, 2015 | 12,519 | 686 | 935 | 692 | 14,832 | 9,662 | (9,740) | 14,754 |

(a)The revenues for wholesale gas services are netted with costs associated with its energy and risk management activities. A reconciliation of operating revenues and intercompany revenues is shown in the following table.

| | Third Party Gross Revenues | Intercompany Revenues | Total Gross Revenues | Less Gross Gas Costs | Operating Revenues |
|---|---|---|---|---|---|
| | (in millions) | | | | |
| Successor – Year Ended December 31, 2017 | $6,152 | $ 481 | $ 6,633 | $6,627 | $ 6 |
| Successor – July 1, 2016 through December 31, 2016 | 5,807 | 333 | 6,140 | 6,116 | 24 |
| | (in millions) | | | | |
| Predecessor – January 1, 2016 through June 30, 2016 | $2,500 | $ 143 | $ 2,643 | $2,675 | $ (32) |
| Predecessor – Year Ended December 31, 2015 | 6,286 | 408 | 6,694 | 6,492 | 202 |

(b) Includes the impact of the Tax Reform Legislation and new income tax apportionment factors in several states resulting from the Company's inclusion in the consolidated Southern Company state tax filings.

NOTES (continued)
Southern Company Gas and Subsidiary Companies 2017 Annual Report

13. QUARTERLY FINANCIAL INFORMATION (UNAUDITED)

Summarized quarterly financial information for the successor year ended December 31, 2017 and the successor period of July 1, 2016 through December 31, 2016 and for the predecessor period of January 1, 2016 through June 30, 2016 are as follows:

| Quarter Ended | Operating Revenues | Operating Income (Loss) | EBIT | Net Income (Loss) Attributable to Southern Company Gas |
|---|---|---|---|---|
| | (in millions) | | | |
| Successor - 2017 | | | | |
| March 2017 | $1,560 | $ 391 | $435 | $ 239 |
| June 2017 | 716 | 96 | 128 | 49 |
| September 2017[a] | 565 | 68 | 118 | 15 |
| December 2017[a][b] | 1,079 | 110 | 129 | (60) |
| Predecessor - January 1, 2016 through June 30, 2016 | (in millions) | | | |
| March 2016 | $1,334 | $ 348 | $351 | $ 182 |
| June 2016 | 571 | (27) | (23) | (51) |
| Successor - July 1, 2016 through December 31, 2016 | (in millions) | | | |
| September 2016 | $543 | $ 12 | $50 | $ 4 |
| December 2016 | 1,109 | 185 | 221 | 110 |

(a) Net income (loss) attributable to Southern Company Gas includes the impact of new income tax apportionment factors in several states resulting from the Company's inclusion in the consolidated Southern Company state tax filings.

(b) Net loss attributable to Southern Company Gas includes the impact of the Tax Reform Legislation.

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

See Note 11 under "Merger with Southern Company" for information on the Merger.

SELECTED CONSOLIDATED FINANCIAL AND OPERATING DATA 2013-2017
Southern Company Gas and Subsidiary Companies 2017 Annual Report

| | Successor | | Predecessor | | | |
|---|---|---|---|---|---|---|
| | 2017 | July 1, 2016 through December 31, 2016 | January 1, 2016 through June 30, 2016 | 2015 | 2014 | 2013 |
| Operating Revenues (in millions) | $3,920 | $ 1,652 | $1,905 | $ 3,941 | $ 5,385 | $ 4,209 |
| Net Income Attributable to Southern Company Gas (in millions) | $243 | $ 114 | $131 | $ 353 | $ 482 | $ 295 |
| Cash Dividends on Common Stock (in millions) | $443 | $ 126 | $128 | $ 244 | $ 233 | $ 222 |
| Return on Average Common Equity (percent) | 2.68 | 1.74 | 3.31 | 9.05 | 12.96 | 8.42 |
| Total Assets (in millions) | $22,987 | $ 21,853 | $14,488 | $ 14,754 | $ 14,888 | $ 14,528 |
| Gross Property Additions (in millions) | $1,525 | $ 632 | $548 | $ 1,027 | $ 769 | $ 731 |
| Capitalization (in millions): | | | | | | |
| Common stock equity | $9,022 | $ 9,109 | $3,933 | $ 3,975 | $ 3,828 | $ 3,613 |
| Long-term debt | 5,891 | 5,259 | 3,709 | 3,275 | 3,581 | 3,791 |
| Total (excluding amounts due within one year) | $14,913 | $ 14,368 | $7,642 | $ 7,250 | $ 7,409 | $ 7,404 |
| Capitalization Ratios (percent): | | | | | | |
| Common stock equity | 60.5 | 63.4 | 51.5 | 54.8 | 51.7 | 48.8 |
| Long-term debt | 39.5 | 36.6 | 48.5 | 45.2 | 48.3 | 51.2 |
| Total (excluding amounts due within one year) | 100.0 | 100.0 | 100.0 | 100.0 | 100.0 | 100.0 |
| Service Contracts (period-end) | 1,184,257 | 1,198,263 | 1,197,096 | 1,205,476 | 1,162,065 | 1,176,908 |
| Customers (period-end) | | | | | | |
| Gas distribution operations | 4,623,249 | 4,586,477 | 4,544,489 | 4,557,729 | 4,529,114 | 4,504,067 |
| Gas marketing services | 773,984 | 655,999 | 630,475 | 654,475 | 633,460 | 632,337 |
| Total (period-end) | 5,397,233 | 5,242,476 | 5,174,964 | 5,212,204 | 5,162,574 | 5,136,404 |
| Employees (period-end) | 5,318 | 5,292 | 5,284 | 5,203 | 5,165 | 6,094 |

SELECTED CONSOLIDATED FINANCIAL AND OPERATING DATA 2013-2017 (continued)
Southern Company Gas and Subsidiary Companies 2017 Annual Report

| | Successor | | Predecessor | | | |
|---|---|---|---|---|---|---|
| | 2017 | July 1, 2016 through December 31, 2016 | January 1, 2016 through June 30, 2016 | 2015 | 2014 | 2013 |
| Operating Revenues (in millions) | | | | | | |
| Residential | $2,100 | $ 899 | $1,101 | $2,129 | $2,877 | $2,422 |
| Commercial | 641 | 260 | 310 | 617 | 861 | 696 |
| Transportation | 811 | 269 | 290 | 526 | 458 | 487 |
| Industrial | 159 | 74 | 72 | 203 | 242 | 180 |
| Other | 209 | 150 | 132 | 466 | 947 | 424 |
| Total | $3,920 | $ 1,652 | $1,905 | $3,941 | $5,385 | $4,209 |
| Heating Degree Days: | | | | | | |
| Illinois | 5,246 | 1,903 | 3,340 | 5,433 | 6,556 | 6,305 |
| Georgia | 1,970 | 727 | 1,448 | 2,204 | 2,882 | 2,689 |
| Gas Sales Volumes (mmBtu in millions): | | | | | | |
| Gas distributions operations | | | | | | |
| Firm | 667 | 274 | 396 | 695 | 766 | 720 |
| Interruptible | 95 | 47 | 49 | 99 | 106 | 111 |
| Total | 762 | 321 | 445 | 794 | 872 | 831 |
| Gas marketing services | | | | | | |
| Firm: | | | | | | |
| Georgia | 23 | 13 | 21 | 35 | 41 | 38 |
| Illinois | 8 | 4 | 8 | 13 | 17 | 9 |
| Other emerging markets | 15 | 5 | 7 | 11 | 10 | 8 |
| Interruptible (large commercial and industrial) | 11 | 6 | 8 | 14 | 17 | 18 |
| Total | 57 | 28 | 44 | 73 | 85 | 73 |
| Market share in Georgia (percent) | 29.2 | 29.4 | 29.3 | 29.7 | 30.6 | 31.4 |
| Wholesale gas services | | | | | | |
| Daily physical sales (mmBtu in millions/day) | 6.4 | 7.2 | 7.6 | 6.8 | 6.3 | 5.7 |

PART III

Items 10 (other than the information under "Code of Ethics" below), 11, 12, 13, and 14 for Southern Company are incorporated by reference to Southern Company's Definitive Proxy Statement relating to the 2018 Annual Meeting of Stockholders. Specifically, reference is made to "Corporate Governance at Southern Company" and "Section 16(a) Beneficial Ownership Reporting Compliance" for Item 10, "Compensation Discussion and Analysis," "Executive Compensation Tables," and "Director Compensation" for Item 11, "Stock Ownership Information," "Executive Compensation Tables," and "Equity Compensation Plan Information" for Item 12, "Southern Company Board" for Item 13, and "Principal Independent Registered Public Accounting Firm Fees" for Item 14.

Items 10 (other than the information under "Code of Ethics" below), 11, 12, 13, and 14 for Alabama Power and Mississippi Power are incorporated by reference to the Definitive Information Statements of Alabama Power and Mississippi Power relating to each of their respective 2018 Annual Meetings of Shareholders. Specifically, reference is made to "Nominees for Election as Directors," "Corporate Governance," and "Section 16(a) Beneficial Ownership Reporting Compliance" for Item 10, "Executive Compensation," "Compensation Committee Interlocks and Insider Participation," "Director Compensation," "Director Deferred Compensation Plan," and "Director Compensation Table" for Item 11, "Stock Ownership Table" and "Executive Compensation" for Item 12, "Certain Relationships and Related Transactions" and "Director Independence" for Item 13, and "Principal Independent Registered Public Accounting Firm Fees" for Item 14.

Items 10, 11, 12, and 13 for each of Georgia Power, Gulf Power, Southern Power, and Southern Company Gas are omitted pursuant to General Instruction I(2)(c) of Form 10-K. Item 14 for each of Georgia Power, Gulf Power, Southern Power, and Southern Company Gas is contained herein.

ITEM 10. DIRECTORS, EXECUTIVE OFFICERS AND CORPORATE GOVERNANCE

Code of Ethics

The registrants collectively have adopted a code of business conduct and ethics (Code of Ethics) that applies to each director, officer, and employee of the registrants and their subsidiaries. The Code of Ethics can be found on Southern Company's website located at www.southerncompany.com. The Code of Ethics is also available free of charge in print to any shareholder by requesting a copy from Myra C. Bierria, Corporate Secretary, Southern Company, 30 Ivan Allen Jr. Boulevard NW, Atlanta, Georgia 30308. Any amendment to or waiver from the Code of Ethics that applies to executive officers and directors will be posted on the website.

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## ITEM 14. PRINCIPAL ACCOUNTANT FEES AND SERVICES

The following represents the fees billed to Georgia Power, Gulf Power, and Southern Power for the last two fiscal years by Deloitte & Touche LLP, each company's principal public accountant for 2017 and 2016:

| | 2017 | 2016 |
|---|---|---|
| | (in thousands) | |
| Georgia Power | | |
| Audit Fees [(1)] | $3,247 | $3,154 |
| Audit-Related Fees [(2)] | 96 | 30 |
| Tax Fees | — | — |
| All Other Fees [(3)] | 1 | 15 |
| Total | $3,344 | $3,199 |
| Gulf Power | | |
| Audit Fees [(1)] | $1,442 | $1,346 |
| Audit-Related Fees | 3 | 3 |
| Tax Fees | — | — |
| All Other Fees [(3)] | — | 2 |
| Total | $1,445 | $1,351 |
| Southern Power | | |
| Audit Fees [(1)] | $1,778 | $1,817 |
| Audit-Related Fees | 439 | 372 |
| Tax Fees | — | — |
| All Other Fees [(3)] | 8 | 6 |
| Total | $2,225 | $2,195 |

(1) Includes services performed in connection with financing transactions.
(2) Includes both audit and non-statutory audit services in 2017 and non-statutory audit services in 2016.
(3) Represents registration fees for attendance at Deloitte & Touche LLP-sponsored education seminars.

The following represents the fees billed to Southern Company Gas for the last two fiscal years by PricewaterhouseCoopers LLP, Southern Company Gas' principal public accountant through February 11, 2016, and Deloitte & Touche LLP, Southern Company Gas' principal public accountant since February 11, 2016:

| | 2017 | 2016 |
|---|---|---|
| | (in thousands) | |
| Southern Company Gas | | |
| Audit Fees [(1)] | $4,449 | $5,131 |
| Audit-Related Fees [(2)] | 579 | 59 |
| Tax Fees [(3)] | — | 65 |
| All Other Fees [(4)] | 8 | 7 |
| Total | $5,036 | $5,262 |

(1) Includes Deloitte & Touche LLP fees in connection with financing transactions and PricewaterhouseCoopers LLP and Deloitte & Touche LLP fees in connection with audits of several subsidiaries in addition to the consolidated audit.
(2) Represents fees for non-statutory audit services in 2017 and a review report on internal controls provided to third parties billed by Deloitte & Touche LLP in 2017 and 2016.
(3) Represents fees billed by Deloitte & Touche LLP for tax compliance services.
(4) Represents registration fees for attendance at Deloitte & Touche LLP-sponsored education seminars and subscription fees for Deloitte & Touche LLP's technical accounting research tool.

The Southern Company Audit Committee (on behalf of Southern Company and its subsidiaries) adopted a Policy of Engagement of the Independent Auditor for Audit and Non-Audit Services that includes requirements for such Audit Committee to pre-approve audit and non-audit services provided by Deloitte & Touche LLP. All of the audit services provided by Deloitte & Touche LLP in fiscal years 2017 and 2016 (described in the footnotes to the table above) and related fees were approved in advance by the Southern Company Audit Committee.

Prior to the closing of the Merger, the Southern Company Gas Audit Committee had responsibility for appointing, setting compensation, and overseeing the work of Southern Company Gas' independent registered public accounting firm. In recognition of this responsibility, Southern Company Gas' Audit Committee adopted a policy that required specific Audit Committee approval before any services were provided by the independent registered public accounting firm. All of the audit services provided by PricewaterhouseCoopers LLP and Deloitte & Touche LLP in fiscal year 2016 (described in the footnotes to the table above) prior to the closing of the Merger and related fees were approved in advance by the Southern Company Gas Audit Committee.

PART IV

Item 15. EXHIBITS AND FINANCIAL STATEMENT SCHEDULES

(a) The following documents are filed as a part of this report on Form 10-K:

(1) Financial Statements and Financial Statement Schedules:

Management's Report on Internal Control Over Financial Reporting for Southern Company and Subsidiary Companies is listed under Item 8 herein.

Management's Report on Internal Control Over Financial Reporting for Alabama Power is listed under Item 8 herein.

Management's Report on Internal Control Over Financial Reporting for Georgia Power is listed under Item 8 herein.

Management's Report on Internal Control Over Financial Reporting for Gulf Power is listed under Item 8 herein.

Management's Report on Internal Control Over Financial Reporting for Mississippi Power is listed under Item 8 herein.

Management's Report on Internal Control Over Financial Reporting for Southern Power and Subsidiary Companies is listed under Item 8 herein.

Management's Report on Internal Control Over Financial Reporting for Southern Company Gas and Subsidiary Companies is listed under Item 8 herein.

Reports of Independent Registered Public Accounting Firm on the financial statements and financial statement schedules for Southern Company and Subsidiary Companies, Alabama Power, Georgia Power, Gulf Power, Mississippi Power, and Southern Company Gas and Subsidiary Companies, as well as the Report of Independent Registered Public Accounting Firm on the financial statements of Southern Power and Subsidiary Companies are listed under Item 8 herein.

The financial statements filed as a part of this report for Southern Company and Subsidiary Companies, Alabama Power, Georgia Power, Gulf Power, Mississippi Power, Southern Power and Subsidiary Companies, and Southern Company Gas and Subsidiary Companies are listed under Item 8 herein.

The financial statement schedules for Southern Company and Subsidiary Companies, Alabama Power, Georgia Power, Gulf Power, Mississippi Power, and Southern Company Gas and Subsidiary Companies are listed in the Index to the Financial Statement Schedules at page S-1.

The financial statements of Southern Natural Gas Company, L.L.C. as of December 31, 2017 and 2016 and for the year ended December 31, 2017 and the four months ended December 31, 2016 are provided by Southern Company Gas as separate financial statements of subsidiaries not consolidated pursuant to Rule 3-09 of Regulation S-X, and are incorporated by reference herein from Exhibit 99(g) hereto.

(2) Exhibits:

Exhibits for Southern Company, Alabama Power, Georgia Power, Gulf Power, Mississippi Power, Southern Power, and Southern Company Gas are listed in the Exhibit Index at page E-1.

Item 16. FORM 10-K SUMMARY

None.

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

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

Opinion on the Financial Statement Schedule

We have audited the consolidated financial statements of Southern Company and Subsidiary Companies (the Company) as of December 31, 2017 and 2016, and for each of the three years in the period ended December 31, 2017, and the Company's internal control over financial reporting as of December 31, 2017, and have issued our report thereon dated February 20, 2018; such report is included elsewhere in this Form 10-K. Our audits also included the consolidated financial statement schedule of the Company (page S-2) listed in the Index at Item 15. This consolidated financial statement schedule is the responsibility of the Company's management. Our responsibility is to express an opinion based on our audits. In our opinion, such consolidated financial statement schedule, when considered in relation to the financial statements taken as a whole, presents fairly, in all material respects, the information set forth therein.

/s/ Deloitte & Touche LLP
Atlanta, Georgia
February 20, 2018

Table of Contents Index to Financial Statements

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the stockholders and the Board of Directors of Alabama Power Company

Opinion on the Financial Statement Schedule

We have audited the financial statements of Alabama Power Company (the Company) (a wholly-owned subsidiary of The Southern Company) as of December 31, 2017 and 2016, and for each of the three years in the period ended December 31, 2017, and have issued our report thereon dated February 20, 2018; such report is included elsewhere in this Form 10-K. Our audits also included the financial statement schedule of the Company (Page S-3) listed in the Index at Item 15. This financial statement schedule is the responsibility of the Company's management. Our responsibility is to express an opinion based on our audits. In our opinion, such financial statement schedule, when considered in relation to the financial statements taken as a whole, presents fairly, in all material respects, the information set forth therein.

/s/ Deloitte & Touche LLP
Birmingham, Alabama
February 20, 2018

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the stockholder and the Board of Directors of Georgia Power Company

Opinion on the Financial Statement Schedule

We have audited the financial statements of Georgia Power Company (the Company) (a wholly-owned subsidiary of The Southern Company) as of December 31, 2017 and 2016, and for each of the three years in the period ended December 31, 2017, and have issued our report thereon dated February 20, 2018; such report is included elsewhere in this Form 10-K. Our audits also included the financial statement schedule of the Company (Page S-4) listed in the Index at Item 15. This financial statement schedule is the responsibility of the Company's management. Our responsibility is to express an opinion based on our audits. In our opinion, such financial statement schedule, when considered in relation to the financial statements taken as a whole, presents fairly, in all material respects, the information set forth therein.

/s/ Deloitte & Touche LLP

Atlanta, Georgia

February 20, 2018

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the stockholder and the Board of Directors of Gulf Power Company

Opinion on the Financial Statement Schedule

We have audited the financial statements of Gulf Power Company (the Company) (a wholly-owned subsidiary of The Southern Company) as of December 31, 2017 and 2016, and for each of the three years in the period ended December 31, 2017, and have issued our report thereon dated February 20, 2018; such report is included elsewhere in this Form 10-K. Our audits also included the financial statement schedule of the Company (Page S-5) listed in the Index at Item 15. This financial statement schedule is the responsibility of the Company's management. Our responsibility is to express an opinion on the Company's financial statement schedule based on our audits. In our opinion, such financial statement schedule, when considered in relation to the financial statements taken as a whole, presents fairly, in all material respects, the information set forth therein.

/s/ Deloitte & Touche LLP

Atlanta, Georgia

February 20, 2018

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the stockholders and the Board of Directors of Mississippi Power Company

Opinion on the Financial Statement Schedule

We have audited the financial statements of Mississippi Power Company (the Company) (a wholly-owned subsidiary of The Southern Company) as of December 31, 2017 and 2016, and for each of the three years in the period ended December 31, 2017, and have issued our report thereon dated February 20, 2018; such report is included elsewhere in this Form 10-K. Our audits also included the financial statement schedule of the Company (Page S-6) listed in the Index at Item 15. This financial statement schedule is the responsibility of the Company's management. Our responsibility is to express an opinion based on our audits. In our opinion, such financial statement schedule, when considered in relation to the financial statements taken as a whole, presents fairly, in all material respects, the information set forth therein.

/s/ Deloitte & Touche LLP

Atlanta, Georgia

February 20, 2018

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the stockholder and the Board of Directors of Southern Company Gas and Subsidiary Companies

Opinion on the Financial Statement Schedule

We have audited the consolidated financial statements of Southern Company Gas and Subsidiary Companies (the Company) (a wholly-owned subsidiary of The Southern Company) as of December 31, 2017 and 2016, and the related consolidated statements of income, comprehensive income, stockholders' equity, and cash flows, for the year ended December 31, 2017 and the six-month periods ended June 30, 2016 (Predecessor) and December 31, 2016 (Successor), and have issued our report thereon dated February 20, 2018; such report is included elsewhere in this Form 10-K. As indicated in that report, we did not audit the financial statements of Southern Natural Gas Company, L.L.C. (SNG), the Company's investment in which is accounted for by the use of the equity method. The Company's consolidated financial statements include its equity investment in SNG of $1,262 million and $1,394 million as of December 31, 2017 and December 31, 2016, respectively, and its earnings from its equity method investment in SNG of $88 million and $56 million for the year ended December 31, 2017 and the six months ended December 31, 2016, respectively. Those statements were audited by other auditors whose report (which expresses an unqualified opinion on SNG's financial statements and contains an emphasis of matter paragraph concerning the extent of its operations and relationships with affiliated entities) have been furnished to us, and our opinion, insofar as it relates to the amounts included for SNG, is based solely on the report of the other auditors. Our audits also included the consolidated financial statement schedule of the Company (Page S-7) listed in the Index at Item 15. This consolidated financial statement schedule is the responsibility of the Company's management. Our responsibility is to express an opinion based on our audits. In our opinion, such consolidated financial statement schedule, when considered in relation to the financial statements taken as a whole, presents fairly, in all material respects, the information set forth therein.

/s/ Deloitte & Touche LLP
Atlanta, Georgia
February 20, 2018

INDEX TO FINANCIAL STATEMENT SCHEDULES



Schedules I through V not listed above are omitted as not applicable or not required. A Schedule II for Southern Power Company and Subsidiary Companies is not being provided because there were no reportable items for the three-year period ended December 31, 2017. Columns omitted from schedules filed have been omitted because the information is not applicable or not required.

THE SOUTHERN COMPANY AND SUBSIDIARY COMPANIES
SCHEDULE II — VALUATION AND QUALIFYING ACCOUNTS
FOR THE YEARS ENDED DECEMBER 31, 2017, 2016, AND 2015
(Stated in Thousands of Dollars)

| | | Additions | | | | |
|---|---|---|---|---|---|---|
| Description | Balance at Beginning of Period | Charged to Income | Charged to Other Accounts | Acquisitions | Deductions (Note) | Balance at End of Period |
| Provision for uncollectible accounts | | | | | | |
| 2017 | $ 43,429 | $55,770 | $ (248) | $ 30 | $ 54,605 | $44,376 |
| 2016 | 13,341 | 39,959 | (1,257) | 40,629 | 49,243 | 43,429 |
| 2015 | 18,253 | 31,074 | — | — | 35,986 | 13,341 |

(Note) Represents write-off of accounts considered to be uncollectible, less recoveries of amounts previously written off.

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ALABAMA POWER COMPANY
SCHEDULE II — VALUATION AND QUALIFYING ACCOUNTS
FOR THE YEARS ENDED DECEMBER 31, 2017, 2016, AND 2015
(Stated in Thousands of Dollars)

| Description | Balance at Beginning of Period | Additions: Charged to Income | Additions: Charged to Other Accounts | Deductions (Note) | Balance at End of Period |
|---|---|---|---|---|---|
| Provision for uncollectible accounts | | | | | |
| 2017 | $ 10,487 | $ 9,367 | $ — | $ 11,075 | $ 8,779 |
| 2016 | 9,597 | 11,310 | — | 10,420 | 10,487 |
| 2015 | 9,143 | 13,500 | — | 13,046 | 9,597 |

(Note) Represents write-off of accounts considered to be uncollectible, less recoveries of amounts previously written off.

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GEORGIA POWER COMPANY
SCHEDULE II — VALUATION AND QUALIFYING ACCOUNTS
FOR THE YEARS ENDED DECEMBER 31, 2017, 2016, AND 2015
(Stated in Thousands of Dollars)

| | | Additions | | | |
|---|---|---|---|---|---|
| Description | Balance at Beginning of Period | Charged to Income | Charged to Other Accounts | Deductions (Note) | Balance at End of Period |
| Provision for uncollectible accounts | | | | | |
| 2017 | $ 2,836 | $11,250 | $ — | $ 11,474 | $ 2,612 |
| 2016 | 2,147 | 14,476 | — | 13,787 | 2,836 |
| 2015 | 6,076 | 16,862 | — | 20,791 | 2,147 |

(Note) Represents write-off of accounts considered to be uncollectible, less recoveries of amounts previously written off.

Table of Contents Index to Financial Statements

GULF POWER COMPANY
SCHEDULE II — VALUATION AND QUALIFYING ACCOUNTS
FOR THE YEARS ENDED DECEMBER 31, 2017, 2016, AND 2015
(Stated in Thousands of Dollars)

| | | Additions | | | |
|---|---|---|---|---|---|
| Description | Balance at Beginning of Period | Charged to Income | Charged to Other Accounts | Deductions (Note) | Balance at End of Period |
| Provision for uncollectible accounts | | | | | |
| 2017 | $ 732 | $ 2,859 | $ — | $ 2,846 | $ 745 |
| 2016 | 775 | 2,946 | — | 2,989 | 732 |
| 2015 | 2,087 | 2,041 | — | 3,353 | 775 |

(Note) Represents write-off of accounts considered to be uncollectible, less recoveries of amounts previously written off.

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MISSISSIPPI POWER COMPANY
SCHEDULE II — VALUATION AND QUALIFYING ACCOUNTS
FOR THE YEARS ENDED DECEMBER 31, 2017, 2016, AND 2015
(Stated in Thousands of Dollars)

| | | Additions | | | |
|---|---|---|---|---|---|
| Description | Balance at Beginning of Period | Charged to Income | Charged to Other Accounts | Deductions (Note) | Balance at End of Period |
| Provision for uncollectible accounts | | | | | |
| 2017 | $ 494 | $ 1,377 | $ — | $ 1,279 | $ 592 |
| 2016 | 287 | 1,295 | — | 1,088 | 494 |
| 2015(*) | 825 | (1,994 ) | — | (1,456 ) | 287 |

(Note) Represents write-off of accounts considered to be uncollectible, less recoveries of amounts previously written off.

(*) The refund ordered by the Mississippi PSC pursuant to the 2015 Mississippi Supreme Court decision relative to a regulatory liability used by Mississippi Power to record financing costs associated with construction of the Kemper County energy facility involved refunding all billed amounts to all historical customers and included an interest component. The refund of approximately $371 million in 2015 was of sufficient magnitude to resolve most past due amounts beyond 30 days aged receivables, accounting for the negative provision of $(2.0) million where risk of collectibility was offset by applying the refund to past due amounts. It was also of sufficient size to offset amounts previously written off in the 2012-2015 time frame, accounting for the net recoveries of $1.5 million.

SOUTHERN COMPANY GAS AND SUBSIDIARY COMPANIES
SCHEDULE II — VALUATION AND QUALIFYING ACCOUNTS
FOR THE SUCCESSOR PERIODS OF JULY 1, 2016 THROUGH DECEMBER 31, 2016
AND THE YEAR ENDED DECEMBER 31, 2017
AND THE PREDECESSOR PERIODS OF JANUARY 1, 2016 THROUGH JUNE 30, 2016
AND THE YEAR ENDED DECEMBER 31, 2015
(Stated in Thousands of Dollars)

| | | Additions | | | |
|---|---|---|---|---|---|
| Description | Balance at Beginning of Period | Charged to Income | Charged to Other Accounts | Deductions (Note) | Balance at End of Period |
| Successor – December 31, 2017 | | | | | |
| Provision for uncollectible accounts | $ 27,316 | $28,022 | $(248) | $ 27,286 | $27,804 |
| Income tax valuation | 19,182 | — | — | 7,910 | 11,272 |
| Successor – December 31, 2016 | | | | | |
| Provision for uncollectible accounts | $ 37,663 | $9,500 | $(1,257) | $ 18,590 | $27,316 |
| Income tax valuation | 19,182 | — | — | — | 19,182 |
| Predecessor – June 30, 2016 | | | | | |
| Provision for uncollectible accounts | $ 29,142 | $15,976 | $1,608 | $ 9,063 | $37,663 |
| Income tax valuation | 19,182 | — | — | — | 19,182 |
| Predecessor – 2015 | | | | | |
| Provision for uncollectible accounts | $ 35,069 | $27,050 | $3,017 | $ 35,994 | $29,142 |
| Income tax valuation | 19,637 | — | — | 455 | 19,182 |

(Note) Represents write-off of accounts considered to be uncollectible, less recoveries of amounts previously written off.

EXHIBIT INDEX

The exhibits below with an asterisk (*) preceding the exhibit number are filed herewith. The remaining exhibits have previously been filed with the SEC and are incorporated herein by reference. The exhibits marked with a pound sign (#) are management contracts or compensatory plans or arrangements required to be identified as such by Item 15 of Form 10-K.

(2) Plan of acquisition, reorganization, arrangement, liquidation or succession

Southern Company

(a) 1 — Agreement and Plan of Merger by and among Southern Company, AMS Corp., and Southern Company Gas, dated August 23, 2015. (Designated in Form 8-K dated August 23, 2015, File No. 1-3526, as Exhibit 2.1.)

Southern Company Gas

(g) 1 — Agreement and Plan of Merger by and among Southern Company, AMS Corp., and Southern Company Gas, dated August 23, 2015. See Exhibit 2(a)1 herein.

(g) 2 — Purchase and Sale Agreement, dated as of July 10, 2016, among Kinder Morgan SNG Operator LLC, Southern Natural Gas Company, L.L.C., and Southern Company.(Designated in Form 8-K dated August 31, 2016, File No. 1-14174, as Exhibit 2.1a.)

(g) 3 — Assignment, Assumption and Novation of Purchase and Sale Agreement, dated as of August 31, 2016, between Southern Company and Evergreen Enterprise Holdings LLC. (Designated in Form 8-K dated August 31, 2016, File No. 1-14174, as Exhibit 2.1b.)

(3) Articles of Incorporation and By-Laws

Southern Company

(a) 1 — Composite Certificate of Incorporation of Southern Company, reflecting all amendments thereto through May 26, 2016. (Designated in Registration No. 33-3546 as Exhibit 4(a), in Certificate of Notification, File No. 70-7341, as Exhibit A, in Certificate of Notification, File No. 70-8181, as Exhibit A, in Form 8-K dated May 26, 2010, File No. 1-3526, as Exhibit 3.1, and in Form 8-K dated May 25, 2016, File No. 1-3526, as Exhibit 3.1.)

(a) 2 — By-laws of Southern Company as amended effective May 25, 2016, and as presently in effect. (Designated in Form 8-K dated May 25, 2016, File No. 1-3526, as Exhibit 3.2.)

Alabama Power

(b) 1 — Charter of Alabama Power and amendments thereto through September 7, 2017. (Designated in Registration Nos. 2-59634 as Exhibit 2(b), 2-60209 as Exhibit 2(c), 2-60484 as Exhibit 2(b), 2-70838 as Exhibit 4(a)-2, 2-85987 as Exhibit 4(a)-2, 33-25539 as Exhibit 4(a)-2, 33-43917 as Exhibit 4(a)-2, in Form 8-K dated February 5, 1992, File No. 1-3164, as Exhibit 4(b)-3, in Form 8-K dated July 8, 1992, File No. 1-3164, as Exhibit 4(b)-3, in Form 8-K dated October 27, 1993, File No. 1-3164, as Exhibits 4(a) and 4(b), in Form 8-K dated November 16, 1993, File No. 1-3164, as Exhibit 4(a), in Certificate of Notification, File No. 70-8191, as Exhibit A, in Form 10-K for the year ended December 31, 1997, File No. 1-3164, as Exhibit 3(b)2, in Form 8-K dated August 10, 1998, File No. 1-3164, as Exhibit 4.4, in Form 10-K for the year ended December 31, 2000, File No. 1-3164, as Exhibit 3(b)2, in Form 10-K for the year ended December 31, 2001, File No. 1-3164, as Exhibit 3(b)2, in Form 8-K dated February 5, 2003, File No. 1-3164, as Exhibit 4.4, in Form 10-Q for the quarter ended March 31, 2003, File No 1-3164, as Exhibit 3(b)1, in Form 8-K dated February 5, 2004, File No. 1-3164, as Exhibit 4.4, in Form 10-Q for the quarter ended March 31, 2006, File No. 1-3164, as Exhibit 3(b)(1), in Form 8-K dated December 5, 2006, File No. 1-3164, as Exhibit 4.2, in Form 8-K dated September 12, 2007, File No. 1-3164, as Exhibit 4.5, in Form 8-K dated October 17, 2007, File No. 1-3164, as Exhibit 4.5, in Form 10-Q for the quarter ended March 31, 2008, File No. 1-3164, as Exhibit 3(b)1, and in Form 8-K dated September 5, 2017, File No. 1-3164, as Exhibit 4.1.)

(b) 2 — Amended and Restated By-laws of Alabama Power effective February 10, 2014, and as presently in effect. (Designated in Form 8-K dated February 10, 2014, File No 1-3164, as Exhibit 3.1.)

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Georgia Power

(c) 1 — Charter of Georgia Power and amendments thereto through October 9, 2007. (Designated in Registration Nos. 2-63392 as Exhibit 2(a)-2, 2-78913 as Exhibits 4(a)-(2) and 4(a)-(3), 2-93039 as Exhibit 4(a)-(2), 2-96810 as Exhibit 4(a)-2, 33-141 as Exhibit 4(a)-(2), 33-1359 as Exhibit 4(a)(2), 33-5405 as Exhibit 4(b)(2), 33-14367 as Exhibits 4(b)-(2) and 4(b)-(3), 33-22504 as Exhibits 4(b)-(2), 4(b)-(3) and 4(b)-(4), in Form 10-K for the year ended December 31, 1991, File No. 1-6468, as Exhibits 4(a)(2) and 4(a)(3), in Registration No. 33-48895 as Exhibits 4(b)-(2) and 4(b)-(3), in Form 8-K dated December 10, 1992, File No. 1-6468 as Exhibit 4(b), in Form 8-K dated June 17, 1993, File No. 1-6468, as Exhibit 4(b), in Form 8-K dated October 20, 1993, File No. 1-6468, as Exhibit 4(b), in Form 10-K for the year ended December 31, 1997, File No. 1-6468, as Exhibit 3(c)2, in Form 10-K for the year ended December 31, 2000, File No. 1-6468, as Exhibit 3(c)2, in Form 8-K dated June 27, 2006, File No. 1-6468, as Exhibit 3.1, and in Form 8-K dated October 3, 2007, File No. 1-6468, as Exhibit 4.5.)

(c) 2 — By-laws of Georgia Power as amended effective November 9, 2016, and as presently in effect. (Designated in Form 8-K dated November 9, 2016, File No. 1-6468, as Exhibit 3.1.)

Gulf Power

(d) 1 — Amended and Restated Articles of Incorporation of Gulf Power and amendments thereto through June 17, 2013. (Designated in Form 8-K dated October 27, 2005, File No. 001-31737, as Exhibit 3.1, in Form 8-K dated November 9, 2005, File No. 001-31737, as Exhibit 4.7, in Form 8-K dated October 16, 2007, File No. 001-31737, as Exhibit 4.5, and in Form 8-K dated June 10, 2013, File No. 001-31737, as Exhibit 4.7.)

(d) 2 — By-laws of Gulf Power as amended effective July 1, 2017, and as presently in effect. (Designated in Form 10-Q for the quarter ended March 31, 2017, File No. 001-31737, as Exhibit 3(d).)

Mississippi Power

(e) 1 — Articles of Incorporation of Mississippi Power, articles of merger of Mississippi Power Company (a Maine corporation) into Mississippi Power and articles of amendment to the articles of incorporation of Mississippi Power through April 2, 2004. (Designated in Registration No. 2-71540 as Exhibit 4(a)-1, in Form U5S for 1987, File No. 30-222-2, as Exhibit B-10, in Registration No. 33-49320 as Exhibit 4(b)-(1), in Form 8-K dated August 5, 1992, File No. 001-11229, as Exhibits 4(b)-2 and 4(b)-3, in Form 8-K dated August 4, 1993, File No. 001-11229, as Exhibit 4(b)-3, in Form 8-K dated August 18, 1993, File No. 001-11229, as Exhibit 4(b)-3, in Form 10-K for the year ended December 31, 1997, File No. 001-11229, as Exhibit 3(e)2, in Form 10-K for the year ended December 31, 2000, File No. 001-11229, as Exhibit 3(e)2, and in Form 8-K dated March 3, 2004, File No. 001-11229, as Exhibit 4.6.)

(e) 2 — By-laws of Mississippi Power as amended effective July 1, 2017, and as presently in effect. (Designated in Form 10-Q for the quarter ended March 31, 2017, File No. 001-11229, as Exhibit 3(e).)

Southern Power

(f) 1 — Certificate of Incorporation of Southern Power Company dated January 8, 2001. (Designated in Registration No. 333-98553 as Exhibit 3.1.)

(f) 2 — By-laws of Southern Power Company effective January 8, 2001. (Designated in Registration No. 333-98553 as Exhibit 3.2.)

Southern Company Gas

(f) 1 — Amended and Restated Articles of Incorporation of Southern Company Gas dated July 11, 2016. (Designated in Form 8-K dated July 8, 2016, File No. 1-14174, as Exhibit 3.1.)

(f) 2 — By-laws of Southern Company Gas effective July 11, 2016. (Designated in Form 8-K dated July 8, 2016, File No. 1-14174, as Exhibit 3.2.)

(4) Instruments Describing Rights of Security Holders, Including Indentures

With respect to each of Southern Company, Alabama Power, Georgia Power, Gulf Power, Mississippi Power, Southern Power Company, and Southern Company Gas, such registrant has excluded certain instruments with respect to long-term debt that does not exceed 10% of the total assets of such registrant and its subsidiaries. Each such registrant agrees, upon request of the SEC, to furnish copies of any or all such instruments to the SEC.

Southern Company

(a) 1 — Senior Note Indenture dated as of January 1, 2007, between Southern Company and Wells Fargo Bank, National Association, as Trustee, and certain indentures supplemental thereto through June 21, 2017. (Designated in Form 8-K dated January 11, 2007, File No. 1-3526, as Exhibit 4.1 , in Form 8-K dated August 21, 2013, File No. 1-3526, as Exhibit 4.2, in Form 8-K dated August 19, 2014, File No. 1-3526, as Exhibit 4.2(b), in Form 8-K dated June 9, 2015, File No. 1-3526, as Exhibit 4.2, in Form 8-K dated May 19, 2016, File No. 1-3526, as Exhibit 4.2(a), in Form 8-K dated May 19, 2016, File No. 1-3526, as Exhibit 4.2(b), in Form 8-K dated May 19, 2016, File No. 1-3526, as Exhibit 4.2(c), in Form 8-K dated May 19, 2016, File No. 1-3526, as Exhibit 4.2(d), in Form 8-K dated May 19, 2016, File No. 1-3526, as Exhibit 4.2(e), in Form 8-K dated May 19, 2016, File No. 1-3526, as Exhibit 4.2(f), in Form 8-K dated May 19, 2016, File No. 1-3526, as Exhibit 4.2(g), and in Form 10-Q for the quarter ended June 30, 2017, File No. 1-3526, as Exhibit 4(a)2.)

(a) 2 — Subordinated Note Indenture dated as of October 1, 2015, between The Southern Company and Wells Fargo Bank, National Association, as Trustee, and indentures supplemental thereto through November 22, 2017. (Designated in Form 8-K dated October 1, 2015, File No. 1-3526, as Exhibit 4.3, in Form 8-K dated October 1, 2015, File No. 1-3526, as Exhibit 4.4, in Form 8-K dated September 12, 2016, File No. 1-3526, as Exhibit 4.4, in Form 8-K dated December 5, 2016, File No. 1-3526, as Exhibit 4.4, in Form 10-Q for the quarter ended June 30, 2017, File No. 1-3526 as Exhibit 4(a)1, and in Form 8-K dated November 17, 2017, File No. 1-3526, as Exhibit 4.4.)

Alabama Power

(b) 1 — Subordinated Note Indenture dated as of January 1, 1997, between Alabama Power and Regions Bank, as Successor Trustee, and certain indentures supplemental thereto through October 2, 2002. (Designated in Form 8-K dated January 9, 1997, File No. 1-3164, as Exhibits 4.1, and in Form 8-K dated September 26, 2002, File No. 3164, as Exhibit 4.9-B.)

(b) 2 — Senior Note Indenture dated as of December 1, 1997, between Alabama Power and Regions Bank, as Successor Trustee, and certain indentures supplemental thereto through November 8, 2017. (Designated in Form 8-K dated December 4, 1997, File No. 1-3164, as Exhibit 4.1, in Form 8-K dated December 6, 2002, File No. 1-3164, as Exhibit 4.2, in Form 8-K dated February 11, 2003, File No. 1-3164, as Exhibit 4.2(a), in Form 8-K dated February 11, 2003, File No. 1-3164, as Exhibit 4.2(b), in Form 8-K dated March 12, 2003, File No. 1-3164, as Exhibit 4.2, in Form 8-K dated May 1, 2003, File No. 1-3164, as Exhibit 4.2, in Form 8-K dated November 14, 2003, File No. 1-3164, as Exhibit 4.2, in Form 8-K dated May 8, 2008, File No. 1-3164, as Exhibit 4.2, in Form 8-K dated February 26, 2009, File No. 1-3164 as Exhibit 4.2, in Form 8-K dated September 27, 2010, File No. 1-3164, as Exhibit 4.2, in Form 8-K dated March 3, 2011, File No. 1-3164, as Exhibit 4.2, in Form 8-K dated May 18, 2011, File No. 1-3164, as Exhibit 4.2(a), in Form 8-K dated May 18, 2011, File No. 1-3164, as Exhibit 4.2(b),in Form 8-K dated January 10, 2012, File No. 1-3164, as Exhibit 4.2, in Form 8-K dated October 9, 2012, File No. 1-3164, as Exhibit 4.2, in Form 8-K dated November 27, 2012, File No. 1-3164, as Exhibit 4.2, in Form 8-K dated December 3, 2013, File No. 1-3164, as Exhibit 4.2, in Form 8-K dated August 20, 2014, File No. 1-3164, as Exhibit 4.6, in Form 8-K dated March 5, 2015, File No. 1-3164, as Exhibit 4.6, in Form 8-K dated April 9, 2015, File No. 1-3164, as Exhibit 4.6(b), in Form 8-K dated January 8, 2016, File No. 1-3164, as Exhibit 4.6, in Form 8-K dated February 27, 2017, File No. 1-3164, as Exhibit 4.6, and in Form 8-K dated November 2, 2017, File No. 1-3164, as Exhibit 4.6.)

(b) 3 — Amended and Restated Trust Agreement of Alabama Power Capital Trust V dated as of October 1, 2002. (Designated in Form 8-K dated September 26, 2002, File No. 1-3164, as Exhibit 4.12-B.)

(b) 4 — Guarantee Agreement relating to Alabama Power Capital Trust V dated as of October 1, 2002. (Designated in Form 8-K dated September 26, 2002, File No. 1-3164, as Exhibit 4.16-B.)