UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549

FORM 10-K

☑ **ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**

For the Fiscal Year Ended December 31, 2018

OR

☐ **TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**

For the Transition Period from to

Commission File Number	Registrant, State of Incorporation, Address and Telephone Number	I.R.S. Employer Identification No.
1-3526	**The Southern Company** (A Delaware Corporation) 30 Ivan Allen Jr. Boulevard, N.W. Atlanta, Georgia 30308 (404) 506-5000	58-0690070
1-3164	**Alabama Power Company** (An Alabama Corporation) 600 North 18th Street Birmingham, Alabama 35291 (205) 257-1000	63-0004250
1-6468	**Georgia Power Company** (A Georgia Corporation) 241 Ralph McGill Boulevard, N.E. Atlanta, Georgia 30308 (404) 506-6526	58-0257110
001-11229	**Mississippi Power Company** (A Mississippi Corporation) 2992 West Beach Boulevard Gulfport, Mississippi 39501 (228) 864-1211	64-0205820
001-37803	**Southern Power Company** (A Delaware Corporation) 30 Ivan Allen Jr. Boulevard, N.W. Atlanta, Georgia 30308 (404) 506-5000	58-2598670
1-14174	**Southern Company Gas** (A Georgia Corporation) Ten Peachtree Place, N.E. Atlanta, Georgia 30309 (404) 584-4000	58-2210952

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

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

Title of each class	Registrant
Common Stock, $5 par value	**The Southern Company**
Junior Subordinated Notes, $25 denominations 6.25% Series 2015A due 2075 5.25% Series 2016A due 2076 5.25% Series 2017B due 2077	
Class A preferred stock, cumulative, $25 stated capital 5.00% Series	**Alabama Power Company**
Junior Subordinated Notes, $25 denominations 5.00% Series 2017A due 2077	**Georgia Power Company**
Senior Notes 1.000% Series 2016A due 2022 1.850% Series 2016B due 2026	**Southern Power Company**

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

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

(1) At December 31, 2018.

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	
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 ☒ (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 ☒ No ☐

Indicate by check mark whether the registrants have submitted electronically every Interactive Data File required to be submitted 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 such files). Yes ☒ 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		
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 ☒ (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 29, 2018: $47.0 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, 2019
The Southern Company	Par Value $5 Per Share	1,034,564,279
Alabama Power Company	Par Value $40 Per Share	30,537,500
Georgia Power Company	Without Par Value	9,261,500
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 2019 Annual Meeting of Stockholders are incorporated by reference into PART III. In addition, specified portions of the Definitive Information Statement on Schedule 14C of Alabama Power Company relating to its 2019 Annual Meeting of Shareholders are incorporated by reference into PART III.

Each of Georgia Power Company, Mississippi 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, 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.

Table of Contents

		Page
	PART I	
Item 1	Business	I-1
	The Southern Company System	I-2
	Construction Programs	I-8
	Financing Programs	I-9
	Fuel Supply	I-9
	Territory Served by the Southern Company System	I-10
	Competition	I-12
	Seasonality	I-13
	Regulation	I-13
	Rate Matters	I-15
	Employee Relations	I-17
Item 1A	Risk Factors	I-19
Item 1B	Unresolved Staff Comments	I-37
Item 2	Properties	I-38
Item 3	Legal Proceedings	I-46
Item 4	Mine Safety Disclosures	I-46
	Executive Officers of Southern Company	I-47
	Executive Officers of Alabama Power	I-49
	PART II	
Item 5	Market for Registrants' Common Equity, Related Stockholder Matters and Issuer Purchases of Equity Securities	II-1
Item 6	Selected Financial Data	II-2
Item 7	Management's Discussion and Analysis of Financial Condition and Results of Operations	II-15
Item 7A	Quantitative and Qualitative Disclosures about Market Risk	II-213
Item 8	Financial Statements and Supplementary Data	II-214
Item 9	Changes in and Disagreements with Accountants on Accounting and Financial Disclosure	II-433
Item 9A	Controls and Procedures	II-433
Item 9B	Other Information	II-440
	PART III	
Item 10	Directors, Executive Officers and Corporate Governance	III-1
Item 11	Executive Compensation	III-1
Item 12	Security Ownership of Certain Beneficial Owners and Management and Related Stockholder Matters	III-1
Item 13	Certain Relationships and Related Transactions, and Director Independence	III-1
Item 14	Principal Accountant Fees and Services	III-2
	PART IV	
Item 15	Exhibits and Financial Statement Schedules	IV-1
Item 16	Form 10-K Summary	IV-1
	Signatures	

DEFINITIONS

When used in this Form 10-K, the following terms will have the meanings indicated.

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
AMEA	Alabama Municipal Electric Authority
AOCI	Accumulated other comprehensive income
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
Bcf	Billion cubic feet
Bechtel	Bechtel Power Corporation, the primary contractor for the remaining construction activities for Plant Vogtle Units 3 and 4
Bechtel Agreement	The October 23, 2017 construction completion agreement between the Vogtle Owners and Bechtel
CCR	Coal combustion residuals
CCR Rule	Disposal of Coal Combustion Residuals from Electric Utilities final rule published by the EPA in 2015
Chattanooga Gas	Chattanooga Gas Company, a wholly-owned subsidiary of Southern Company Gas
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
Customer Refunds	Refunds issued to Georgia Power customers in 2018 as ordered by the Georgia PSC related to the Guarantee Settlement Agreement
CWIP	Construction work in progress
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
Dalton Pipeline	A pipeline facility in Georgia in which Southern Company Gas has a 50% undivided ownership interest
DOE	U.S. Department of Energy
Duke Energy Florida	Duke Energy Florida, LLC
EBIT	Earnings before interest and taxes
ECM	Mississippi Power's energy cost management clause
ECO Plan	Mississippi Power's environmental compliance overview plan
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
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

DEFINITIONS
(continued)

Term	Meaning
FASB	Financial Accounting Standards Board
FERC	Federal Energy Regulatory Commission
FFB	Federal Financing Bank
Fitch	Fitch Ratings, Inc.
FMPA	Florida Municipal Power Agency
GAAP	U.S. generally accepted accounting principles
Georgia Power	Georgia Power Company
Georgia Power 2019 Base Rate Case	Georgia Power's base rate case scheduled to be filed by July 1, 2019
Georgia Power Tax Reform Settlement Agreement	A settlement agreement between Georgia Power and the staff of the Georgia PSC regarding the retail rate impact of the Tax Reform Legislation, as approved by the Georgia PSC on April 3, 2018
GHG	Greenhouse gas
Guarantee Settlement Agreement	The June 9, 2017 settlement agreement between the Vogtle Owners and Toshiba related to certain payment obligations of the EPC Contractor guaranteed by Toshiba
Gulf Power	Gulf Power Company
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 Southern Company Gas' natural gas usage and operating revenues are generally higher
HLBV	Hypothetical liquidation at book value
Horizon Pipeline	Horizon Pipeline Company, LLC
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
Illinois Commission	Illinois Commerce Commission
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
Internal Revenue Code	Internal Revenue Code of 1986, as amended
IPP	Independent Power Producer
IRP	Integrated Resource Plan
IRS	Internal Revenue Service
ITAAC	Inspections, Tests, Analyses, and Acceptance Criteria, standards established by the NRC
ITC	Investment tax credit
JEA	Jacksonville Electric Authority
KUA	Kissimmee Utility Authority
KW	Kilowatt
KWH	Kilowatt-hour
LIBOR	London Interbank Offered Rate
LIFO	Last-in, first-out
LNG	Liquefied natural gas
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
LOCOM	Lower of weighted average cost or current market price
LTSA	Long-term service agreement
Marketers	Marketers selling retail natural gas in Georgia and certificated by the Georgia PSC

DEFINITIONS
(continued)

Term	Meaning
MEAG	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
MGP	Manufactured gas plant
Mississippi Power	Mississippi Power Company
mmBtu	Million British thermal units
Moody's	Moody's Investors Service, Inc.
MPUS	Mississippi Public Utilities Staff
MRA	Municipal and Rural Associations
MW	Megawatt
MWH	Megawatt hour
natural gas distribution utilities	Southern Company Gas' natural gas distribution utilities (Nicor Gas, Atlanta Gas Light, Virginia Natural Gas, Elizabethtown Gas, Florida City Gas, Chattanooga Gas, and Elkton Gas as of June 30, 2018) (Nicor Gas, Atlanta Gas Light, Virginia Natural Gas, and Chattanooga Gas as of July 29, 2018)
NCCR	Georgia Power's Nuclear Construction Cost Recovery
NDR	Alabama Power's Natural Disaster Reserve
NextEra Energy	NextEra Energy, Inc.
Nicor Gas	Northern Illinois Gas Company, a wholly-owned subsidiary of Southern Company Gas
NO_X	Nitrogen oxide
NRC	U.S. Nuclear Regulatory Commission
NYMEX	New York Mercantile Exchange, Inc.
NYSE	New York Stock Exchange
OCI	Other comprehensive income
OPC	Oglethorpe Power Corporation (an Electric Membership Corporation)
OTC	Over-the-counter
OUC	Orlando Utilities Commission
PATH Act	Protecting Americans from Tax Hikes Act
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
PEP	Mississippi Power's Performance Evaluation Plan
Piedmont	Piedmont Natural Gas Company, Inc.
Pivotal Home Solutions	Nicor Energy Services Company, until June 4, 2018 a wholly-owned subsidiary of Southern Company Gas, doing business as Pivotal Home Solutions
Pivotal Utility Holdings	Pivotal Utility Holdings, Inc., until July 29, 2018 a wholly-owned subsidiary of Southern Company Gas, doing business as Elizabethtown Gas (until July 1, 2018), Elkton Gas (until July 1, 2018), and Florida City Gas
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
PRP	Pipeline Replacement Program, Atlanta Gas Light's 15-year infrastructure replacement program, which ended in December 2013
PSC	Public Service Commission
PTC	Production tax credit

DEFINITIONS
(continued)

Term	Meaning
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
registrants	Southern Company, Alabama Power, Georgia Power, Mississippi Power, Southern Power Company, and Southern Company Gas
revenue from contracts with customers	Revenue from contracts accounted for under the guidance of ASC 606, Revenue from Contracts with Customers
ROE	Return on equity
RUS	Rural Utilities Service
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
SEPA	Southeastern Power Administration
Sequent	Sequent Energy Management, L.P.
SERC	Southeastern Electric Reliability Council
SNG	Southern Natural Gas Company, L.L.C.
SO_2	Sulfur dioxide
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 Gas Dispositions	Southern Company Gas' disposition of Pivotal Home Solutions, Pivotal Utility Holdings' disposition of Elizabethtown Gas and Elkton Gas, and NUI Corporation's disposition of Pivotal Utility Holdings, which primarily consisted of Florida City 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
SouthStar	SouthStar Energy Services, LLC
SP Solar	SP Solar Holdings I, LP
SP Wind	SP Wind Holdings II, LLC
SRR	Mississippi Power's System Restoration Rider, a tariff for retail property damage reserve
STRIDE	Atlanta Gas Light's Strategic Infrastructure Development and Enhancement program
Subsidiary Registrants	Alabama Power, Georgia Power, Mississippi Power, Southern Power, and Southern Company Gas
Tax Reform Legislation	The Tax Cuts and Jobs Act, which became effective on January 1, 2018
Toshiba	Toshiba Corporation, parent company of Westinghouse
traditional electric operating companies	Alabama Power, Georgia Power, Gulf Power, and Mississippi Power through December 31, 2018; Alabama Power, Georgia Power, and Mississippi Power as of January 1, 2019
Triton	Triton Container Investments, LLC

DEFINITIONS
(continued)

Term	Meaning
VCM	Vogtle Construction Monitoring
VIE	Variable interest entity
Virginia Commission	Virginia State Corporation Commission
Virginia Natural Gas	Virginia Natural Gas, Inc., a wholly-owned subsidiary of Southern Company Gas
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, and rejected in bankruptcy in July 2017, 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, MEAG, and Dalton
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
WACOG	Weighted average cost of gas
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 business, customer and sales growth, economic conditions, fuel and environmental cost recovery and other rate actions, projected equity ratios, 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 dispositions, filings with state and federal regulatory authorities, federal and state income tax benefits, estimated sales and purchases under power sale and purchase agreements, and estimated construction plans and expenditures. In some cases, forward-looking statements can be identified by terminology such as "may," "will," "could," "would," "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, and also changes in tax (including the Tax Reform Legislation) 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 extent and timing of costs and liabilities to comply with federal and state laws, regulations, and legal requirements related to CCR, including amounts for required closure of ash ponds and ground water monitoring;
- current and future litigation or regulatory investigations, proceedings, or inquiries, including litigation and other disputes related to the Kemper County energy facility;
- the effects, extent, and timing of the entry of additional competition in the markets in which Southern Company's subsidiaries operate, including from the development and deployment of alternative energy sources;
- variations in demand for electricity and natural gas;
- available sources and costs of natural gas and other fuels;
- the ability to complete necessary or desirable pipeline expansion or infrastructure projects, limits on pipeline capacity, and operational interruptions to natural gas distribution and transmission activities;
- transmission constraints;
- effects of inflation;
- the ability to control costs and avoid cost and schedule overruns during the development, construction, and operation of facilities, including Plant Vogtle Units 3 and 4 which includes components based on new technology that only recently began initial operation in the global nuclear industry at this scale, including changes in labor costs, availability, and productivity; challenges with management of contractors, subcontractors, or vendors; adverse weather conditions; shortages, increased costs, or 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; engineering or design problems; design and other licensing-based compliance matters, including the timely resolution of ITAAC and the related approvals by the NRC; challenges with 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 employee and retiree benefit plans and nuclear decommissioning trust funds;
- advances in technology;
- the ability to control operating and maintenance costs;
- 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 ROE, equity ratios, and fuel and other cost recovery mechanisms;

CAUTIONARY STATEMENT REGARDING FORWARD-LOOKING INFORMATION

(continued)

- 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;
- under certain specified circumstances, a decision by holders of more than 10% of the ownership interests of Plant Vogtle Units 3 and 4 not to proceed with construction and the ability of other Vogtle Owners to tender a portion of their ownership interests to Georgia Power following certain construction cost increases;
- in the event Georgia Power becomes obligated to provide funding to MEAG with respect to the portion of MEAG's ownership interest in Plant Vogtle Units 3 and 4 involving JEA, any inability of Georgia Power to receive repayment of such funding;
- the inherent risks involved in operating and constructing nuclear generating facilities;
- 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 of Plant Mankato, which cannot be assured to be completed or beneficial to Southern Company or its subsidiaries;
- 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;
- access to capital markets and other financing sources;
- changes in Southern Company's and any of its subsidiaries' credit ratings;
- 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, 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, 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, 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.

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.

On January 1, 2019, Southern Company completed its sale of Gulf Power to NextEra Energy for an aggregate cash purchase price of approximately $5.8 billion (less $1.3 billion of indebtedness assumed), subject to customary working capital adjustments. Gulf Power is an electric utility serving retail customers in the northwestern portion of Florida. See Note 15 to the financial statements under "Southern Company's Sale of Gulf Power" in Item 8 herein for additional information.

In addition, Southern Company owns all of the common stock of Southern Power Company, which is also an operating public utility company. 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 Southern Power parent company. 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 Power Company is a corporation organized under the laws of Delaware on January 8, 2001. On May 22, 2018, Southern Power sold a noncontrolling 33% equity interest in SP Solar, a limited partnership indirectly owning substantially all of Southern Power's solar facilities, for approximately $1.2 billion and, on December 11, 2018, Southern Power sold a noncontrolling tax equity interest in SP Wind, a holding company owning a portfolio of eight operating wind facilities, for approximately $1.2 billion. Southern Power also sold all of its equity interests in Plant Oleander and Plant Stanton Unit A (together, the Florida Plants) to NextEra Energy on December 4, 2018 for $203 million. On November 5, 2018, Southern Power entered into an agreement to sell all of its equity interests in Plant Mankato (including the 385-MW expansion currently under construction) for approximately $650 million. The transaction is subject to FERC and state commission approvals and is expected to close mid-2019. The ultimate outcome of this matter cannot be determined at this time. See "The Southern Company System – Southern Power" herein and Note 15 to the financial statements in Item 8 herein for additional information.

Southern Company acquired all of the common stock of Southern Company Gas in July 2016. Southern Company Gas is an energy services holding company whose primary business is the distribution of natural gas in four states - Illinois, Georgia, Virginia, and Tennessee - 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, which was founded in 1856. In July 2018, Southern Company Gas completed sales of three of its natural gas distribution utilities (Elizabethtown Gas, Florida City Gas, and Elkton Gas). In June 2018, Southern Company Gas also completed the sale of Pivotal Home Solutions, which provided home equipment protection products and services. See "The Southern Company System – Southern Company Gas" herein and Note 15 to the financial statements in Item 8 herein for additional information.

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, treasury, legal, tax, information technology, marketing, auditing, insurance and pension administration, human resources, systems and procedures, digital wireless communications, cellular tower space, 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 energy solutions, including distributed energy infrastructure, energy efficiency products and services, and utility infrastructure services, to customers.

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. See Note 7 to the financial statements in Item 8 herein for additional information.

Segment information for Southern Company and Southern Company Gas is included in Note 16 to the financial statements 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 various reliability agreements with certain neighboring utilities, 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 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 North American 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. In connection with the sale of Gulf Power, an appendix was added to the IIC setting forth terms and conditions governing Gulf Power's continued participation in the IIC for a defined transition period that, subject to certain potential adjustments, is scheduled to end on January 1, 2024.

Southern Power and Southern Linc have secured from the traditional electric operating companies certain services which are furnished 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, dispositions, and sales of partnership interests, 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. At December 31, 2018, Southern Power's generation fleet, which is owned in part with its various partners, totaled 11,888 MWs of nameplate capacity in commercial operation (including 4,508 MWs of nameplate capacity owned by its subsidiaries and including Plant Mankato, which is classified as held for sale in the financial statements). In addition, Southern Power Company has other subsidiaries that are pursuing additional natural gas generation and other renewable generation development opportunities. The generation assets of Southern Power Company's subsidiaries are not included in the power pool.

On May 22, 2018, Southern Power sold a noncontrolling 33% equity interest in SP Solar, a limited partnership indirectly owning substantially all of Southern Power's solar facilities. On December 11, 2018, Southern Power sold a noncontrolling tax equity interest in SP Wind, a holding company which owns a portfolio of eight operating wind farms.

In addition, on December 4, 2018, Southern Power sold all of its equity interests in the Florida Plants and, in November 2018, entered into an agreement to sell Plant Mankato. The completion of the disposition of Plant Mankato is subject to the expansion unit reaching commercial operation as well as various other customary conditions to closing, including FERC and state commission approvals, and is expected to close mid-2019. The ultimate outcome of this matter cannot be determined at this time.

A majority of Southern Power's partnerships in renewable facilities allow for the sharing of cash distributions and tax benefits at differing percentages, with Southern Power being the controlling member and thus consolidating the assets and operations of the partnerships. At December 31, 2018, Southern Power has three tax-equity partnership arrangements where the tax-equity investors receive substantially all of the tax benefits, including ITCs and PTCs. In addition, Southern Power holds controlling interests in eight partnerships in solar facilities through SP Solar. For seven of these solar partnerships, Southern Power and its new 33% partner, Global Atlantic, are entitled to 51% of all cash distributions and the respective partner that holds the Class B membership interests is entitled to 49% of all cash distributions. For the Desert Stateline partnership, Southern Power and Global Atlantic are entitled to 66% of all cash distributions and the Class B member is entitled to 34% of all cash distributions. In addition, Southern Power and Global Atlantic are entitled to substantially all of the federal tax benefits with respect to these eight partnership entities. Finally, for the Roserock partnership, Southern Power is entitled to 51% of all cash distributions and substantially all of the federal tax benefits, with the Class B member entitled to 49% of all cash distributions.

See PROPERTIES in Item 2 herein and Note 15 to the financial statements under "Southern Power" in Item 8 herein for additional information regarding Southern Power's acquisitions, dispositions, 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 investments associated with the wind and natural gas facilities currently under construction, as well as other capacity and energy contracts, Southern Power has an average investment coverage ratio, at December 31, 2018, of 93% through 2023 and 91% through 2028, with an average remaining contract duration of approximately 14 years (including Plant Mankato, which is classified as held for sale in the financial statements).

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, 2018:

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 EMC (NCEMC)	90-180	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
Dahlberg Units 1, 3, and 5	Cobb EMC	224	through Dec. 2027
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	through Dec. 2035
Franklin Unit 2	Cobb EMC	100	through Dec. 2027
Franklin Unit 3	Morgan Stanley Capital Group	200-300	through Dec. 2033
Franklin Unit 3	Dalton	70	through Dec. 2027
Franklin Unit 3	Dalton	16	through Dec. 2019
Harris Unit 1	Georgia Power	640	through May 2030
Harris Unit 2	Georgia Power	657	through May 2019
Harris Unit 2	AMEA[2]	25	through Dec. 2025
Mankato[3]	Northern States Power Company	375	through July 2026
Mankato[3]	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
Rowan CT Unit 1	North Carolina Municipal Power Agency 1	150	through Dec. 2030
Rowan CT Units 2 and 3	EnergyUnited	100-175	Jan. 2022 – Dec. 2025
Rowan CT Unit 3	EnergyUnited	113	through Dec. 2023
Rowan CC Unit 4	EnergyUnited	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	Macquarie	150-250	Jan. 2019 – Nov. 2020
Wansley Unit 6	Century Aluminum	158	Jan. 2019 – Dec. 2020
Wansley Unit 7	JEA[6]	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) AMEA will also be served by Plant Franklin Unit 1 through December 2019.
(3) On November 5, 2018, Southern Power entered into an agreement with Northern States Power to sell all of its equity interests in Plant Mankato (including the 385-MW expansion currently under construction). The ultimate outcome of this matter cannot be determined at this time. See Note 15 to the financial statements under "Southern Power – Sales of Natural Gas Plants" in Item 8 herein for additional information.
(4) Subject to commercial operation of the 385-MW expansion project.
(5) Represents sale of power purchased from NCEMC under a PPA.
(6) JEA will also be served by Plant Wansley Unit 6 during 2019.

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	0-145	through Dec. 2027
Flint EMC	135-194	through Dec. 2024
Dalton	53-92	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[2]			
Adobe	Southern California Edison Company	20	through June 2034
Apex	Nevada Power Company	20	through Dec. 2037
Boulder 1	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	Southern California Edison Company	300	through Sept. 2036
East Pecos	Austin Energy	119	through April 2032
Garland A	Southern California Edison Company	20	through Sept. 2036
Garland	Southern California Edison Company	180	through Oct. 2031
Gaskell West 1	Southern California Edison Company	20	through March 2038
Granville	Duke Energy Progress, LLC	3	through Oct. 2032
Henrietta	Pacific Gas & Electric Company[3]	100	through Sept. 2036
Imperial Valley	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	99% to Pacific Gas & Electric Company[3] and 1% to City of Roseville, California	32	through Dec. 2043
Macho Springs	El Paso Electric Company	50	through May 2034
Morelos	Pacific Gas & Electric Company[3]	15	through Feb. 2036
North Star	Pacific Gas & Electric Company[3]	60	through June 2035
Pawpaw	Georgia Power	30	through March 2046
Roserock	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	Shell Energy North America (US), LP	204	through Nov. 2019
Tranquillity	Southern California Edison Company	204	Dec. 2019 – Nov. 2034
Wind[4]			
Bethel	Google Inc.	225	through Jan. 2029
Cactus Flats	General Mills, Inc.	98	through July 2033
Cactus Flats	General Motors Company	50	through July 2030
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 April 2036
Grant Wind	Northeast Texas Electric Cooperative	50	through April 2036
Grant Wind	Western Farmers Electric Cooperative	50	through April 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
Reading[5]	Royal Caribbean Cruises Ltd.	200	April 2020 – March 2032
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	Equinix Enterprises, Inc.	100	through Oct. 2028
Wake Wind	Owens Corning	125	through Oct. 2028
Wildhorse[5]	Arkansas Electric Cooperative Corporation	100	Oct. 2019 – Sept. 2039

(1) MWs shown are for 100% of the PPA, which is based on demonstrated capacity of the facility.

(2) In May 2018, Southern Power sold a noncontrolling 33% equity interest in SP Solar (a limited partnership indirectly owning all of Southern Power's solar facilities, except the Roserock and Gaskell West facilities). SP Solar is the 51% majority owner of Boulder 1, Garland, Henrietta, Imperial Valley, Lost Hills Blackwell, North Star, and Tranquillity; the 66% majority owner of Desert Stateline; and the sole owner of the remaining SP Solar facilities. Southern Power is the 51% majority owner of Roserock and also the controlling partner in a tax equity partnership owning Gaskell West. All of these entities are consolidated subsidiaries of Southern Power.

(3) See Note 1 to the financial statements under "Revenues – Concentration of Revenue" in Item 8 herein for additional information on Pacific Gas & Electric Company's bankruptcy filing.

(4) In December 2018, Southern Power sold a noncontrolling tax equity interest in SP Wind (which owns all of Southern Power's wind facilities, except Cactus Flats and the two wind projects under construction, Reading and Wildhorse). SP Wind is the 90.1% majority owner of Wake Wind and owns 100% of the remaining SP Wind facilities. Southern Power owns 100% of Reading and Wildhorse and is the controlling partner in a tax equity partnership owning Cactus Flats. All of these entities are consolidated subsidiaries of Southern Power.

(5) Subject to commercial operation.

For the year ended December 31, 2018, approximately 9.8% 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 pipeline investments, wholesale gas services, and gas marketing services. During the fourth quarter 2018, Southern Company Gas changed its reportable segments to further align with the way its new Chief Operating Decision Maker reviews operating results and has reclassified prior years' data to conform to the new reportable segment presentation. This change resulted in a new reportable segment, gas pipeline investments, which was formerly included in gas midstream operations. Gas pipeline investments consists primarily of joint ventures in natural gas pipeline investments including a 50% interest in SNG, two significant pipeline construction projects, and a 50% joint ownership interest in the Dalton Pipeline. Gas distribution operations, wholesale gas services, and gas marketing services continue to remain as separate reportable segments and reflect the impact of the Southern Company Gas Dispositions. The all other non-reportable segment includes segments below the quantitative threshold for separate disclosure, including the storage and fuels operations that were formerly included in gas midstream operations, and other subsidiaries that fall below the quantitative threshold for separate disclosure.

Gas distribution operations, the largest segment of Southern Company Gas' business, operates, constructs, and maintains approximately 75,200 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 4.2 million customers across four states.

On July 1, 2018, a Southern Company Gas subsidiary, Pivotal Utility Holdings, completed the sales of the assets of two of its natural gas distribution utilities, Elizabethtown Gas and Elkton Gas, to South Jersey Industries, Inc. On July 29, 2018, Southern Company Gas and its wholly-owned direct subsidiary, NUI Corporation, completed the stock sale of Pivotal Utility Holdings, which then primarily consisted of Florida City Gas, to NextEra Energy. The transactions raised approximately $2.3 billion in proceeds. See Note 15 to the financial statements under "Southern Company Gas" in Item 8 herein for additional information.

Gas pipeline investments includes joint ventures in natural gas pipeline investments that enable the provision of diverse sources of natural gas supplies to the customers of Southern Company Gas. SNG, the largest natural gas pipeline investment, 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.

Wholesale gas services consists of Sequent 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 marketing services is comprised of SouthStar and provides natural gas commodity and related services to customers in competitive markets or markets that provide for customer choice. SouthStar, serving approximately 697,000 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.

On June 4, 2018, Southern Company Gas completed the stock sale of Pivotal Home Solutions to American Water Enterprises LLC for $365 million. See Note 15 to the financial statements under "Southern Company Gas" in Item 8 herein for additional information.

Other Businesses

PowerSecure, which was acquired by Southern Company in 2016, provides energy solutions, including distributed energy infrastructure, energy efficiency products and services, and utility infrastructure services, to customers.

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 2019 through 2023, see MANAGEMENT'S DISCUSSION AND ANALYSIS – FINANCIAL CONDITION AND LIQUIDITY – "Capital Requirements and Contractual Obligations" of each registrant 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. In 2019, the construction program is expected to be apportioned approximately as follows:

	Southern Company system[a][b]	Alabama Power[a]	Georgia Power[a]	Mississippi Power
		(in billions)		
New generation	$ 1.6	$ —	$ 1.6	$ —
Environmental compliance[c]	0.5	0.2	0.2	—
Generation maintenance	0.9	0.4	0.4	0.1
Transmission	1.0	0.3	0.6	—
Distribution	1.1	0.5	0.5	0.1
Nuclear fuel	0.2	0.1	0.1	—
General plant	0.5	0.2	0.2	—
	5.8	1.8	3.7	0.2
Southern Power[d]	0.3			
Southern Company Gas[e]	1.6			
Other subsidiaries	0.3			
Total[a]	$ 8.0	$ 1.8	$ 3.7	$ 0.2

(a) Totals may not add due to rounding.

(b) Includes the Subsidiary Registrants, 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 pending regulation of CO_2 emissions from fossil-fuel-fired electric generating units or costs associated with ash pond closure and groundwater monitoring under the CCR Rule and the related state rules. 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) Excludes up to approximately $0.5 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.

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 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.

The construction program also includes Plant Vogtle Units 3 and 4, which includes components based on new technology that only recently began initial operation in the global nuclear industry at this scale and which may be subject to additional revised cost estimates during construction. The ability to control costs and avoid cost and schedule 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, availability, and productivity; challenges with management of contractors, subcontractors, or vendors; adverse weather conditions; shortages, increased costs, or 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; engineering or design problems; design and other licensing-based compliance matters, including the timely resolution of ITAAC and the related approvals by the NRC; challenges with start-up activities, including major equipment failure and system integration; and/or operational performance. See Note 2 to the financial statements under "Georgia Power – Nuclear Construction" 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 and Note 5 to the financial statements under "Joint Ownership Agreements" in Item 8 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 8 to the financial statements 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 2016 through 2018.

The traditional electric operating companies have agreements in place from which they expect to receive substantially all of their 2019 coal burn requirements. These agreements have terms ranging between one and four years. In 2018, the weighted average sulfur content of all coal burned by the traditional electric operating companies was 1.06%. This sulfur level, along with banked SO_2 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 2018, the Southern Company system did not purchase any SO_2 allowances, annual NOx emission allowances, or seasonal NOx 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 2019, SCS has contracted for 557 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 have remaining

terms ranging from one to 17 years. The remaining term lengths for the enrichment services contracts range from five to 10 years. 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 under "Nuclear Fuel Disposal Costs" in Item 8 herein for additional information.

Natural Gas

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 regulatory agencies in the states where Southern Company Gas operates. Southern Company Gas purchases natural gas supplies in the open market by contracting with producers and marketers and, for the natural gas distribution utilities except Nicor Gas, from its wholly-owned subsidiary, Sequent, under asset management agreements 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

As of January 1, 2019, the territory in which the traditional electric operating companies provide retail electric service comprises most of the states of Alabama and Georgia, together with southeastern Mississippi. See Note 15 to the financial statements under "Southern Company's Sale of Gulf Power" in Item 8 herein for information on the sale of Gulf Power. 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 January 1, 2019, the territory had an area of approximately 114,000 square miles and an estimated population of approximately 16 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 11 municipally-owned electric distribution systems, all of which are served indirectly through sales to AMEA, and two rural distributing cooperative associations. The sales contract with AMEA is scheduled to expire on December 31, 2025. 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.

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 Southern Company and 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 Southern Company and 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 January 1, 2019, there were approximately 58 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. As of December 31, 2018, 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 and Note 5 to the financial statements under "Joint Ownership Agreements" in Item 8 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 has entered into a separate agreement with PowerSouth involving interconnection between their systems. The delivery of capacity and energy from PowerSouth to certain distributing cooperatives in the service territory of Alabama 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, some of which are jointly owned with Georgia Power, and power purchased from other suppliers. OPC and the 38 retail electric distribution cooperatives are members of Georgia Transmission Corporation, an EMC (GTC), which provides transmission services to its members and third parties. See PROPERTIES – "Electric – Jointly-Owned Facilities" in Item 2 herein and Note 5 to the financial statements under "Joint Ownership Agreements" in Item 8 herein for additional information regarding Georgia Power's jointly-owned facilities.

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

As of January 1, 2019, there were approximately 71 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, 2018, 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 Southern Power through a service agreement. See PROPERTIES – "Jointly-Owned Facilities" in Item 2 herein and Note 5 to the financial statements under "Joint Ownership Agreements" in Item 8 herein for additional information.

Georgia Power has entered into substantially similar agreements with GTC, 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 Georgia Power, 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 four 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, 2018 are as follows:

Utility	State	Number of customers	Approximate miles of pipe
		(in thousands)	
Nicor Gas	Illinois	2,237	34,285
Atlanta Gas Light	Georgia	1,643	33,610
Virginia Natural Gas	Virginia	301	5,650
Chattanooga Gas	Tennessee	67	1,655
Total		4,248	75,200

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 a CPCN that are subsequently annexed to municipalities may continue to be served by the holder of the CPCN, 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, 2018, Alabama Power had cogeneration contracts in effect with nine industrial customers. Under the terms of these contracts, Alabama Power purchases excess energy generated by such companies. During 2018, Alabama Power purchased approximately 99 million KWHs from such companies at a cost of $3 million.

As of December 31, 2018, Georgia Power had contracts in effect with 28 small power producers whereby Georgia Power purchases their excess generation. During 2018, Georgia Power purchased 2.1 billion KWHs from such companies at a cost of $140 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 2018, Georgia Power purchased 26 million KWHs at a cost of $0.8 million from these facilities.

Also during 2018, Georgia Power purchased energy from three customer-owned generating facilities. These customers provide energy with no capacity commitment and are not dispatched by Georgia Power. During 2018, Georgia Power purchased a total of 341 million KWHs from the three customers at a cost of approximately $28 million.

As of December 31, 2018, 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 2018, 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. While the electric power sales of some of the traditional electric operating companies peak in the summer, others peak in the winter. In the aggregate, electric power sales peak during the summer with a smaller peak during the winter. 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, 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

States

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, 2018, 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 1,101,402 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 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. Also in 2016, Alabama Rivers Alliance and American Rivers filed a second rehearing request and 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 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 and, on July 6, 2018, vacated the FERC's 2013 order for the new 30-year license and remanded the proceeding to the FERC. Alabama Power continues to operate the Coosa River developments under annual licenses issued by the FERC. The ultimate outcome of this matter cannot be determined at this time.

In 2018, 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.

On May 31, 2018, Georgia Power filed an application to relicense the Wallace Dam project on the Oconee River. The current Wallace Dam project license will expire on June 1, 2020. On July 3, 2018, Georgia Power filed a Notice of Intent to relicense the Lloyd Shoals project on the Ocmulgee River. The application to relicense the Lloyd Shoals project is expected to be filed with the FERC by December 31, 2021. The current Lloyd Shoals project license will expire on December 31, 2023. On December 18, 2018, Georgia Power filed applications to surrender the Langdale and Riverview hydroelectric projects on the Chattahoochee River upon their license expirations on December 31, 2023. Both projects together represent 1,520 KWs of Georgia Power's hydro fleet capacity.

Georgia Power and OPC also have a license, expiring in 2027, for the Rocky Mountain project, a pure pumped storage facility of 903,000 KW installed 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 2034-2066 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 2 to the financial statements under "Georgia Power – Nuclear Construction" in Item 8 herein for additional information.

See Notes 3 and 6 to the financial statements under "Nuclear Insurance" and "Nuclear Decommissioning," respectively, in Item 8 herein for information on nuclear insurance and nuclear decommissioning costs.

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 MGP sites, which are generally recovered through existing ratemaking provisions. See Note 3 to the financial statements under "Environmental Matters" in Item 8 herein for additional information.

Compliance with environmental laws and resulting regulations, including, but not limited to, proposed and existing regulations related to air quality, water quality, CCR, and global climate issues, has been, and will continue to be, a significant focus for each of the registrants and SEGCO. Compliance with any new or revised environmental laws and regulations could affect many areas of the traditional electric operating companies', Southern Power's, SEGCO's, and Southern Company Gas' operations. See MANAGEMENT'S DISCUSSION AND ANALYSIS – FUTURE EARNINGS POTENTIAL – "Environmental Matters" of each of the registrants in Item 7 herein for additional information about environmental issues.

The Southern Company system's ultimate environmental compliance strategy and future environmental expenditures will depend on various factors, such as state adoption and implementation of requirements, the availability and cost of any deployed control technology, fuel prices, 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, or changing fuel sources for certain existing units, as well as related upgrades to the transmission and distribution (electric and natural gas) systems. 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/or 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 each of the registrants 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 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 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 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 2 to the financial statements in Item 8 herein for a discussion of rate matters and certain cost recovery mechanisms. Also, see Note 1 to the financial statements 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 and Note 2 to the financial statements under "Georgia Power – Integrated Resource Plan" in Item 8 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 2 to the financial statements under "Georgia Power – 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 since 2011.

See Note 2 to the financial statements 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 for 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.

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 17.3% of Mississippi Power's total operating revenues in 2018 and are generally subject to 10-year rolling 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' natural gas distribution utilities are subject to regulation and oversight by their respective state regulatory agencies. 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.

With the exception of Atlanta Gas Light, which operates in a deregulated environment in which 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, are authorized 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. 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 2 to the financial statements under "Southern Company Gas" 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.

Alabama Power

Triennially, Alabama Power provides an IRP report to the Alabama PSC. This report overviews Alabama Power's resource planning process and contains information that serves as the foundation for certain decisions affecting Alabama Power's portfolio of supply-side and demand-side resources. The IRP report facilitates Alabama Power's ability to provide reliable and cost-effective electric service to customers, while accounting for the risks and uncertainties inherent in planning for resources sufficient to meet expected customer demand. Under State of Alabama law, a CPCN must be obtained from the Alabama PSC before Alabama Power constructs any new generating facility, unless such construction is deemed an ordinary extension in the usual course of business.

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 2 to the financial statements under "Georgia Power – Rate Plans," " – Integrated Resource Plan," and " – Nuclear Construction" in Item 8 herein for additional information.

Mississippi Power

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 filed a Reserve Margin Plan (RMP) on August 6, 2018. The RMP includes many of the same aspects of a traditional IRP, but the RMP also contains alternatives proposed by Mississippi Power to address its existing reserve capacity, which is greater than the level required to meet Mississippi Power's projected summer peak demand. Mississippi Power developed the alternatives by evaluating the economics of each unit in Mississippi Power's fleet, the opportunities currently available in the wholesale market, and the operational constraints of the Southern Company system. The ultimate outcome of this matter cannot be determined at this time. For additional information, see Note 2 to the financial statements under "Kemper County Energy Facility" in Item 8 herein.

Employee Relations

The Southern Company system had a total of 29,192 employees on its payroll at January 1, 2019.

	Employees at January 1, 2019
Alabama Power	6,650
Georgia Power	6,967
Mississippi Power	1,053
PowerSecure	1,743
SCS	3,799
Southern Company Gas	4,389
Southern Nuclear	3,870
Southern Power	491
Other	230
Total	29,192

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.

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 15, 2020. The agreements also make the terms of the Southern Company Gas pension plan subject to collective bargaining with the unions when significant changes to the benefit accruals are considered by Southern Company Gas.

Item 1A. RISK FACTORS

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

UTILITY REGULATORY, LEGISLATIVE, AND LITIGATION RISKS

Southern Company and its subsidiaries are subject to substantial 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 are subject to substantial regulation from federal, state, and local regulatory agencies and are required to comply with numerous laws and regulations and to obtain numerous permits, approvals, and certificates from governmental agencies. 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 and for some of its storage assets 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. Retaining this authority from the FERC is important to the traditional electric operating companies' and Southern Power's ability to remain competitive in the wholesale electric markets.

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 and satisfying related AROs are significant. The costs of compliance with current and future environmental laws and related AROs 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. Compliance with existing environmental requirements involves significant capital and operating costs including the settlement of AROs, 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 future compliance expenditures will continue to be significant.

The EPA has adopted and is implementing regulations governing air and water quality under the Clean Air Act and regulations governing cooling water intake structures and effluent guidelines for steam electric generating plants under the Clean Water Act. The EPA has also adopted regulations governing the disposal of CCR, including coal ash and gypsum, in landfills and surface impoundments at active generating power plants. 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. The traditional electric operating companies will continue to periodically update their ARO cost estimates.

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 environmental laws and regulations may be adopted or become applicable to the Southern Company system. In addition, existing environmental laws and regulations may be impacted by related legal challenges.

Litigation over environmental issues and claims of various types, including property damage, personal injury, common law nuisance, and citizen enforcement of environmental requirements 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.

Compliance with any new or revised environmental laws or regulations could affect many areas of the Southern Company system's operations. The Southern Company system's ultimate environmental compliance strategy and future environmental 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, or changing fuel sources for certain existing units, as well as related upgrades to the Southern Company system's transmission and distribution (electric and natural gas) systems. 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/or 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.

The Southern Company system may be exposed to regulatory and financial risks related to the impact of GHG legislation, regulation, and emission reduction goals.

The EPA has published 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). On August 31, 2018, the EPA published a proposed rule known as the Affordable Clean Energy (ACE) Rule, which is intended to replace a regulation enacted in 2015 known as the Clean Power Plan (CPP), that would limit CO_2 emissions from existing fossil fuel-fired electric generating units. The CPP has been stayed by the U.S. Supreme Court since 2016. The ACE Rule would require states to develop GHG unit-specific emission rate standards based on heat-rate efficiency improvements for existing fossil fuel-fired steam units. As proposed, combustion turbines, including natural gas combined cycles, are not affected sources. As of January 1, 2019, the Southern Company system has ownership interests in 40 fossil fuel-fired steam units to which the proposed ACE Rule is applicable. The ultimate impact of this rule to the Southern Company system is currently unknown and will depend on changes between the proposal and the final rule, subsequent state plan developments and requirements, and any associated legal challenges.

The EPA also has proposed a review of final rules adopted in 2015 to establish performance standards for new, modified, and reconstructed electric utility generating units. The impact of any changes will depend on the content of any final rule adopted by the EPA and the outcome of any related legal challenges.

In April 2018, Southern Company established an intermediate goal of a 50% reduction in carbon emissions from 2007 levels by 2030 and a long-term goal of low- to no-carbon operations by 2050. To achieve these goals, the Southern Company system expects to continue growing its renewable energy portfolio, optimize technology advancements to modernize its transmission and distribution systems, increase the use of natural gas for generation, complete ongoing construction projects, including Georgia Power's interest in Plant Vogtle Units 3 and 4, invest in energy efficiency, and continue research and development efforts focused on technologies to lower GHG emissions. The Southern Company system's ability to achieve these goals also will be dependent on many external factors, including supportive national energy policies, low natural gas prices, and the development, deployment, and advancement of relevant energy technologies.

Costs associated with GHG legislation, regulation, and emission reduction goals could be significant. However, the ultimate impact will depend on various factors, such as state adoption and implementation of requirements, low natural gas prices, the development, deployment, and advancement of relevant energy technologies, the ability to recover costs through existing ratemaking provisions, 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, including, but not limited to, the imposition of a carbon tax, may create additional demand for natural gas, both for production of electricity and direct use in homes and businesses. Future GHG constraints designed to minimize emissions from natural gas could likewise result in increased costs to the Southern Company system and affect the demand for natural gas as well as the prices charged to customers and the competitive position of natural gas.

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

The traditional electric operating companies currently own and operate transmission facilities as part of a vertically integrated utility. A small percentage of transmission revenues are collected through the wholesale electric tariff but the majority 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. 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.

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 generation, transmission, and distribution facilities and 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;
- operating limitations that may be imposed by environmental or other regulatory requirements or in connection with joint owner arrangements;
- labor disputes;
- physical attacks;
- fuel or material supply interruptions and/or shortages;
- 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 failures;
- cyber intrusions;
- environmental events, such as spills or releases; and
- catastrophic events such as fires, earthquakes, explosions, floods, tornadoes, hurricanes and other storms, droughts, pandemic health events, 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 registrant.

Operation of nuclear facilities involves inherent risks, including environmental, safety, health, regulatory, natural disasters, cyber intrusions or physical attacks, 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 at January 1, 2019. 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, 2018. 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;
- actual or threatened cyber intrusions or physical attacks; 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, actual or potential threats of cyber intrusions or physical attacks 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 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 Subsidiary Registrants to operate and could adversely affect financial results and liquidity.

The Subsidiary Registrants 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 third-party 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 restored in a timely manner, the affected Subsidiary Registrant 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 Subsidiary Registrants 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 have been immaterial incidents of phishing and attempted financial fraud across the Southern Company system, there has been no material impact on business or operations from these attacks. However, the registrants cannot guarantee that security efforts will prevent breaches, operational incidents, or other breakdowns of information technology systems and network infrastructure and cannot provide any assurance that such incidents will not have a material adverse effect in the future.

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 restored in a timely manner, 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. In addition, as cybercriminals become more sophisticated, the cost of proactive defensive measures may increase.

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

The Southern Company system may not be able to obtain adequate natural gas, fuel supplies, and other resources 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. Additionally, the traditional electric operating companies and Southern

Power need adequate access to water, which is drawn from nearby sources to aid in the production of electricity and, once it is used, returned to its source. 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, or the availability of water, 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 and expect to continue to increase such dependence. 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 Southern California Edison accounted for 9.8%, 6.8%, and 6.2%, respectively, of Southern Power's total revenues for the year ended December 31, 2018. 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, including as a result of a general default or bankruptcy, 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. See Note 1 to the financial statements under "Revenues – Concentration of Revenue" in Item 8 herein for additional information on Pacific Gas & Electric Company's bankruptcy filing.

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) as well as certain non-affiliated customers. Southern Company Gas' wholesale gas

services has a concentration of credit risk for services it provides to its counterparties, which is generally concentrated in 20 of its counterparties.

The profits earned from the management of affiliate assets are shared with the respective affiliate's customers (and for Atlanta Gas Light with the Georgia PSC's Universal Service Fund), except for Chattanooga 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.

The financial results of Southern Company Gas' wholesale gas services could be significantly impacted if any of its agreements with its affiliated or non-affiliated customers 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 Subsidiary Registrants 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 Subsidiary Registrants require ongoing expenditures, including those to meet AROs and other environmental standards and goals.

General

The businesses of the registrants require substantial expenditures for investments in new facilities and, for the traditional electric operating companies, capital improvements to transmission, distribution, and generation facilities, for Southern Power, capital improvements to generation facilities, and, for Southern Company Gas, capital improvements to natural gas distribution and storage facilities. These expenditures also include those to meet AROs and environmental standards and goals. 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 may 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, increased costs, or inconsistent quality of equipment, materials, and labor;
- changes in labor costs, availability, and productivity;
- challenges related to management of contractors, subcontractors, or vendors;
- work stoppages;
- contractor or supplier delay;
- non-performance under construction, operating, or other agreements;
- delays in or failure to receive necessary permits, approvals, tax credits, and other regulatory authorizations;
- delays in start-up activities (including major equipment failure and system integration) and/or operational performance;
- 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 any legal challenges to projects, including legal challenges to regulatory approvals;
- failure to construct in accordance with permitting and licensing requirements (including satisfaction of NRC requirements);
- failure to satisfy any environmental performance standards and the requirements of tax credits and other incentives;
- continued public and policymaker support for projects;
- adverse weather conditions or natural disasters;
- 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
- increased financing costs as a result of changes in market interest rates or as a result of project delays.

If a Subsidiary Registrant 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, as well as other costs associated with the closure and/or abandonment of the construction project. See Note 2 to the financial statements under "Kemper County Energy Facility" for information related to the abandonment of and related closure activities and costs for the mine and gasifier-related assets at the Kemper County energy facility.

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, including rights to cause the cancellation of a construction project under certain circumstances.

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. See Note 2 to the financial statements under "FERC Matters – Southern Company Gas" for information regarding the Atlantic Coast Pipeline construction delays and the associated cost increase.

Construction delays could result in the loss of otherwise available tax credits and incentives. Furthermore, if construction projects are not completed according to specification, a registrant 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 expenditures to maintain efficiency, to comply with changing environmental requirements, to provide safe and reliable operations, and/or to meet related retirement obligations.

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

Background

In 2009, the Georgia PSC certified construction of Plant Vogtle Units 3 and 4. Georgia Power holds a 45.7% ownership interest in 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. In March 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 in July 2017 when Georgia Power, acting for itself and as agent for the other Vogtle Owners, and the EPC Contractor entered into the Vogtle Services Agreement. Under the Vogtle Services Agreement, Westinghouse provides facility design and engineering services, procurement and technical support, and staff augmentation on a time and materials cost basis.

In October 2017, Georgia Power, acting for itself and as agent for the other Vogtle Owners, executed the Bechtel Agreement, a cost reimbursable plus fee arrangement, whereby Bechtel is 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.

Cost and Schedule

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

		(in billions)
Base project capital cost forecast[(a)(b)]	$	8.0
Construction contingency estimate		0.4
Total project capital cost forecast[(a)(b)]		8.4
Net investment as of December 31, 2018[(b)]		(4.6)
Remaining estimate to complete[(a)]	**$**	**3.8**

(a) Excludes financing costs expected to be capitalized through AFUDC of approximately $315 million.

(b) Net of $1.7 billion received from Toshiba under the Guarantee Settlement Agreement and approximately $188 million in related 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 $1.9 billion had been incurred through December 31, 2018.

As construction continues, challenges with management of contractors, subcontractors, and vendors; labor productivity, availability, and/or cost escalation; procurement, fabrication, delivery, assembly, and/or installation and testing, including any required engineering changes, of plant systems, structures, and components (some of which are based on new technology that only recently began initial operation in the global nuclear industry at this scale); or other issues could arise and change the projected schedule and estimated cost. Monthly construction production targets required to maintain the current project schedule will continue to increase significantly throughout 2019. To meet these increasing monthly targets, existing craft construction productivity must improve and additional craft laborers must be retained and deployed.

Georgia Power and Southern Nuclear believe it is a leading practice in connection with a construction project of this size and complexity to periodically validate recent construction progress in comparison to the projected schedule and to verify and update quantities of commodities remaining to install, labor productivity, and forecasted staffing needs. This verification process, led by Southern Nuclear, was underway as of December 31, 2018 and is expected to be completed during the second quarter 2019. Georgia Power currently does not anticipate any material changes to the total estimated project capital cost forecast for Plant Vogtle Units 3 and 4 or the expected in-service dates of November 2021 and November 2022, respectively, resulting from this verification process. However, the ultimate impact on cost and schedule, if any, will not be known until the verification process is completed. Georgia Power is required to report the results and any project impacts to the Georgia PSC by May 15, 2019.

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 ITAAC 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. However, any extension of the project schedule is currently estimated to result in additional base capital costs of approximately $50 million per month, based on Georgia Power's ownership interests, and AFUDC of approximately $12 million per month. While Georgia Power is not precluded from seeking recovery of any future capital cost forecast increase, management will ultimately determine whether or not to seek recovery. Any further changes to the capital cost forecast that are not expected to be recoverable through regulated rates will be required to be charged to income and such charges could be material.

Joint Owner Contracts

In November 2017, the Vogtle Owners entered into an amendment to their joint ownership agreements for Plant Vogtle Units 3 and 4 to provide for, among other conditions, additional Vogtle Owner approval requirements. Effective August 31, 2018, the Vogtle Owners further amended the joint ownership agreements to clarify and provide procedures for certain provisions of the joint ownership agreements related to adverse events that require the vote of the holders of at least 90% of the ownership interests in Plant Vogtle Units 3 and 4 to continue construction (as amended, and together with the November 2017 amendment, the Vogtle Joint Ownership Agreements).

As a result of the increase in the total project capital cost forecast and Georgia Power's decision not to seek rate recovery of the increase in the base capital costs as described below, the holders of at least 90% of the ownership interests in Plant Vogtle Units 3 and 4 were required to vote to continue construction. On September 26, 2018, the Vogtle Owners unanimously voted to continue construction of Plant Vogtle Units 3 and 4.

Amendments to the Vogtle Joint Ownership Agreements

In connection with the vote to continue construction, Georgia Power entered into (i) a binding term sheet (Vogtle Owner Term Sheet) with the other Vogtle Owners and MEAG's wholly-owned subsidiaries MEAG Power SPVJ, LLC (MEAG SPVJ), MEAG Power SPVM, LLC (MEAG SPVM), and MEAG Power SPVP, LLC (MEAG SPVP) to take certain actions which partially mitigate potential financial exposure for the other Vogtle Owners, including additional amendments to the Vogtle Joint Ownership Agreements and the purchase of PTCs from the other Vogtle Owners, and (ii) a term sheet (MEAG Term Sheet) with MEAG and MEAG SPVJ to provide funding with respect to MEAG SPVJ's ownership interest in Plant Vogtle Units 3 and 4 (Project J) under certain circumstances. On January 14, 2019, Georgia Power, MEAG, and MEAG SPVJ entered into an agreement to implement the provisions of the MEAG Term Sheet (MEAG Funding Agreement). On February 18, 2019, Georgia Power, the other Vogtle Owners, and MEAG's wholly-owned subsidiaries MEAG SPVJ, MEAG SPVM, and MEAG SPVP entered into certain amendments to the Vogtle Joint Ownership Agreements to implement the provisions of the Vogtle Owner Term Sheet (Global Amendments).

Pursuant to the Global Amendments, and consistent with the Vogtle Owner Term Sheet, the Vogtle Joint Ownership Agreements were modified as follows: (i) each Vogtle Owner must pay its proportionate share of qualifying construction costs for Plant Vogtle Units 3 and 4 based on its ownership percentage up to the estimated cost at completion (EAC) for Plant Vogtle Units 3 and 4 which formed the basis of Georgia Power's forecast of $8.4 billion in the nineteenth VCM plus $800 million; (ii) Georgia Power will be responsible for 55.7% of actual qualifying construction costs between $800 million and $1.6 billion over the EAC in the nineteenth VCM (resulting in $80 million of potential additional costs to Georgia Power), with the remaining Vogtle Owners responsible for 44.3% of such costs pro rata in accordance with their respective ownership interests; and (iii) Georgia

Power will be responsible for 65.7% of qualifying construction costs between $1.6 billion and $2.1 billion over the EAC in the nineteenth VCM (resulting in a further $100 million of potential additional costs to Georgia Power), with the remaining Vogtle Owners responsible for 34.3% of such costs pro rata in accordance with their respective ownership interests.

If the EAC is revised and exceeds the EAC in the nineteenth VCM by more than $2.1 billion, each of the other Vogtle Owners will have a one-time option at the time the project budget forecast is so revised to tender a portion of its ownership interest to Georgia Power in exchange for Georgia Power's agreement to pay 100% of such Vogtle Owner's remaining share of total construction costs in excess of the EAC in the nineteenth VCM plus $2.1 billion. In this event, Georgia Power will have the option of cancelling the project in lieu of purchasing a portion of the ownership interest of any other Vogtle Owner. If Georgia Power accepts the offer to purchase a portion of another Vogtle Owner's ownership interest in Plant Vogtle Units 3 and 4, the ownership interest(s) to be conveyed from the tendering Vogtle Owner(s) to Georgia Power will be calculated based on the proportion of the cumulative amount of construction costs paid by each such tendering Vogtle Owner(s) and by Georgia Power as of the COD of Plant Vogtle Unit 4. For purposes of this calculation, payments made by Georgia Power on behalf of another Vogtle Owner in accordance with the second and third items described in the paragraph above will be treated as payments made by the applicable Vogtle Owner.

In the event the actual costs of construction at completion of a Unit are less than the EAC reflected in the nineteenth VCM report and such Unit is placed in service in accordance with the schedule projected in the nineteenth VCM report (i.e., Plant Vogtle Unit 3 is placed in service by November 2021 or Plant Vogtle Unit 4 is placed in service by November 2022), Georgia Power will be entitled to 60.7% of the cost savings with respect to the relevant Unit and the remaining Vogtle Owners will be entitled to 39.3% of such savings on a pro rata basis in accordance with their respective ownership interests.

For purposes of the foregoing provisions, qualifying construction costs will not include costs (i) resulting from force majeure events, including governmental actions or inactions (or significant delays associated with issuance of such actions) that affect the licensing, completion, start-up, operations, or financing of Plant Vogtle Units 3 and 4, administrative proceedings or litigation regarding ITAAC or other regulatory challenges to commencement of operation of Plant Vogtle Units 3 and 4, and changes in laws or regulations governing Plant Vogtle Units 3 and 4, (ii) legal fees and legal expenses incurred due to litigation with contractors or subcontractors that are not subsidiaries or affiliates of Southern Company, and (iii) additional costs caused by requests from the Vogtle Owners other than Georgia Power, except for the exercise of a right to vote granted under the Vogtle Joint Ownership Agreements, that increase costs by $100,000 or more.

Pursuant to the Global Amendments, and consistent with the Vogtle Owner Term Sheet, the provisions of the Vogtle Joint Ownership Agreements requiring that Vogtle Owners holding 90% of the ownership interests in Plant Vogtle Units 3 and 4 vote to continue construction following certain adverse events (Project Adverse Events) were modified. Pursuant to the Global Amendments, the holders of at least 90% of the ownership interests in Plant Vogtle Units 3 and 4 must vote to continue construction if certain Project Adverse Events occur, including: (i) the bankruptcy of Toshiba; (ii) the termination or rejection in bankruptcy of certain agreements, including the Vogtle Services Agreement, the Bechtel Agreement, or the agency agreement with Southern Nuclear; (iii) Georgia Power publicly announces its intention not to submit for rate recovery any portion of its investment in Plant Vogtle Units 3 and 4 or the Georgia PSC 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, excluding any additional amounts paid by Georgia Power on behalf of the other Vogtle Owners pursuant to the Global Amendments described above and the first 6% of costs during any six-month VCM reporting period that are disallowed by the Georgia PSC for recovery, or for which Georgia Power elects not to seek cost recovery, through retail rates; and (iv) an incremental extension of one year or more over the most recently approved schedule. Under the Global Amendments, Georgia Power may cancel the project at any time in its sole discretion.

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 Global Amendments provide that if the holders of at least 90% of the ownership interests fail to vote in favor of continuing the project following any future Project Adverse Event, work on Plant Vogtle Units 3 and 4 will continue for a period of 30 days if the holders of more than 50% of the ownership interests vote in favor of continuing construction (Majority Voting Owners). In such a case, the Vogtle Owners (i) have agreed to negotiate in good faith towards the resumption of the project, (ii) if no agreement is reached during such 30-day period, the project will be cancelled, and (iii) in the event of such a cancellation, the Majority Voting Owners will be obligated to reimburse any other Vogtle Owner for the incremental costs it incurred during such 30-day negotiation period.

Purchase of PTCs During Commercial Operation

Pursuant to the Global Amendments, and consistent with the Vogtle Owner Term Sheet, Georgia Power has agreed to purchase additional PTCs from OPC, Dalton, MEAG SPVM, MEAG SPVP, and MEAG SPVJ (to the extent any MEAG SPVJ PTC rights remain after any purchases required under the MEAG Funding Agreement as described below) at varying purchase prices dependent upon the actual cost to complete construction of Plant Vogtle Units 3 and 4 as compared to the EAC reflected in the nineteenth VCM report. The purchases are at the option of the applicable Vogtle Owner.

Potential Funding to MEAG Project J

Pursuant to the MEAG Funding Agreement, and consistent with the MEAG Term Sheet, if MEAG SPVJ is unable to make its payments due under the Vogtle Joint Ownership Agreements solely as a result of the occurrence of one of the following situations that materially impedes access to capital markets for MEAG for Project J: (i) the conduct of JEA or the City of Jacksonville, such as JEA's legal challenges of its obligations under a PPA with MEAG (PPA-J), or (ii) PPA-J is declared void by a court of competent jurisdiction or rejected by JEA under the applicable provisions of the U.S. Bankruptcy Code (each of (i) and (ii), a JEA Default), at MEAG's request, Georgia Power will purchase from MEAG SPVJ the rights to PTCs attributable to MEAG SPVJ's share of Plant Vogtle Units 3 and 4 (approximately 206 MWs) within 30 days of such request at varying prices dependent upon the stage of construction of Plant Vogtle Units 3 and 4. The aggregate purchase price of the PTCs, together with any advances made as described in the next paragraph, shall not exceed $300 million.

At the option of MEAG, as an alternative or supplement to Georgia Power's purchase of PTCs as described above, Georgia Power has agreed to provide up to $250 million in funding to MEAG for Project J in the form of advances (either advances under the Vogtle Joint Ownership Agreements or the purchase of MEAG Project J bonds, at the discretion of Georgia Power), subject to any required approvals of the Georgia PSC and the DOE.

In the event MEAG SPVJ certifies to Georgia Power that it is unable to fund its obligations under the Vogtle Joint Ownership Agreements as a result of a JEA Default and Georgia Power becomes obligated to provide funding as described above, MEAG is required to (i) assign to Georgia Power its right to vote on any future Project Adverse Event and (ii) diligently pursue JEA for its breach of PPA-J. In addition, Georgia Power agreed that it will not sue MEAG for any amounts due from MEAG SPVJ under MEAG's guarantee of MEAG SPVJ's obligations so long as MEAG SPVJ complies with the terms of the MEAG Funding Agreement as to its payment obligations and the other non-payment provisions of the Vogtle Joint Ownership Agreements.

Under the terms of the MEAG Funding Agreement, Georgia Power may cancel the project in lieu of providing funding in the form of advances or PTC purchases.

Regulatory Matters

In December 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 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 $5.68 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 $5.68 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 related Customer Refunds) was 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 $100 million, $25 million, and $20 million in 2018, 2017, and 2016, respectively, and are estimated to have negative earnings impacts of approximately $75 million in 2019 and an aggregate of approximately $615 million from 2020 to 2022.

In its January 11, 2018 order, the Georgia PSC also stated if other conditions change and assumptions upon which Georgia Power's seventeenth VCM report are based do not materialize, the Georgia PSC reserved the right to reconsider the decision to continue construction.

On February 12, 2018, Georgia Interfaith Power & Light, Inc. (GIPL) and Partnership for Southern Equity, Inc. (PSE) filed a petition appealing the Georgia PSC's January 11, 2018 order with the Fulton County Superior Court. On March 8, 2018, Georgia Watch filed a similar appeal to the Fulton County Superior Court for judicial review of the Georgia PSC's decision and denial of Georgia Watch's motion for reconsideration. On December 21, 2018, the Fulton County Superior Court granted Georgia Power's motion to dismiss the two appeals. On January 9, 2019, GIPL, PSE, and Georgia Watch filed an appeal of this decision with the Georgia Court of Appeals. Georgia Power believes the appeal has no merit; however, an adverse outcome in the appeal combined with subsequent adverse action by the Georgia PSC could have a material impact on Southern Company's and Georgia Power's results of operations, financial condition, and liquidity.

In preparation for its nineteenth VCM filing, Georgia Power requested Southern Nuclear to perform a full cost reforecast for the project. This reforecast, performed prior to the nineteenth VCM filing, resulted in a $0.7 billion increase to the base capital cost forecast reported in the second quarter 2018. This base cost increase primarily resulted from changed assumptions related to the finalization of contract scopes and management responsibilities for Bechtel and over 60 subcontractors, labor productivity rates, and craft labor incentives, as well as the related levels of project management, oversight, and support, including field supervision and engineering support.

Although Georgia Power believes these incremental costs are reasonable and necessary to complete the project and the Georgia PSC's order in the seventeenth VCM proceeding specifically states that the construction of Plant Vogtle Units 3 and 4 is not subject to a cost cap, Georgia Power did not seek rate recovery for these cost increases included in the current base capital cost forecast (or any related financing costs) in the nineteenth VCM report. In connection with future VCM filings, Georgia Power may request the Georgia PSC to evaluate costs currently included in the construction contingency estimate for rate recovery as and when they are appropriately included in the base capital cost forecast. After considering the significant level of uncertainty that exists regarding the future recoverability of costs included in the construction contingency estimate since the ultimate outcome of these matters is subject to the outcome of future assessments by management, as well as Georgia PSC decisions in these future regulatory proceedings, Georgia Power recorded a total pre-tax charge to income of $1.1 billion ($0.8 billion after tax) in the second quarter 2018, which includes the total increase in the base capital cost forecast and construction contingency estimate.

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

See Note 2 to the financial statements under "Georgia Power – Nuclear Construction" in Item 8 herein 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 its 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' income 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 income until the project is placed in service.

Work continues with state and federal agencies to obtain the required permits to begin construction on the PennEast Pipeline. Any material delays may impact forecasted capital expenditures and the expected in-service date.

The Atlantic Coast Pipeline has experienced challenges to its permits since construction began in 2018. During the third and fourth quarters 2018, a FERC stop work order, together with delays in obtaining permits necessary for construction and construction delays due to judicial actions, impacted the cost and schedule for the project. As a result, total project cost estimates have increased and the operator of the joint venture currently expects to achieve a late 2020 in-service date for at least

key segments of the Atlantic Coast Pipeline, while the remainder may extend into early 2021. Abnormal weather, work delays (including due to judicial or regulatory action), and other conditions may result in additional cost or schedule modifications, which could result in an impairment of Southern Company Gas' investment and could have a material impact on Southern Company's and Southern Company Gas' financial statements.

The ultimate outcome of these matters cannot be determined at this time and the occurrence of these or any other 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, physical or cyber attacks, and other catastrophic events; and
- federal, state, and foreign energy and environmental regulation and legislation.

These factors could increase the expenses and/or reduce the revenues of the registrants. For the traditional electric operating companies and Southern Company Gas' regulated gas distribution operations, such impacts may not be fully recoverable through rates.

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, both of which could negatively impact the cash flows of the affected traditional electric operating company or Southern Company Gas and of 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 Subsidiary Registrants.

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 Subsidiary Registrants.

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, 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 a registrant's 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 a Subsidiary Registrant 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. While the electric power sales of some of the traditional electric operating companies peak in the summer, others peak in the winter. In the aggregate, electric power sales peak during the summer with a smaller peak during the winter. Additionally, Southern Power has variability in its revenues from renewable generation facilities due to seasonal weather patterns primarily from wind and sun. 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 Subsidiary Registrants 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 Subsidiary Registrants have significant investments in the Atlantic and Gulf Coast regions and Southern Power and Southern Company Gas have investments in various states which could be subject to severe weather and natural disasters, including wildfires. Further, severe drought conditions can reduce the availability of water and restrict or prevent the operation of certain generating facilities. There have been multiple significant hurricanes in the Southern Company system service territory in recent years.

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. For example, at December 31, 2018, Georgia Power had a substantial underrecovered balance in its storm cost recovery balance as a result of multiple recent significant hurricanes in its service territory. 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 on 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 and may impact customers' ability to perform under existing PPAs. See Note 1 to the financial statements under "Revenues – Concentration of Revenue" in Item 8 herein for additional information on Pacific Gas & Electric Company's bankruptcy filing. Any significant loss of customers or reduction in demand for energy could have a material negative impact on a registrant'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, as well as recent dispositions, and may in the future make additional acquisitions, dispositions, or other strategic ventures or investments, including the pending disposition by Southern Power of Plant Mankato, which cannot be assured to be completed or beneficial to Southern Company or its subsidiaries. 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, dispositions, and sales of partnership interests, development and construction of new generating facilities, and entry into PPAs primarily with investor-owned utilities, IPPs, 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 adequate or expected funds or 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 may not appropriately evaluate the likelihood or quantify the exposure from identified risks;
- they may result in decreased earnings, revenues, or cash flow;
- Southern Company, Southern Company Gas, and certain of their subsidiaries have retained obligations in connection with transitional agreements related to dispositions that subject these companies to additional risk;
- Southern Company or the applicable subsidiary may not be able to achieve the expected financial benefits from the use of funds generated by any dispositions;
- 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 regulated rates may not be recoverable.

Southern Company and Southern Company Gas are holding companies and Southern Power owns many of its assets indirectly through subsidiaries. Each of these companies is 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' and many of Southern Power's 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, Southern Company Gas' and, to a certain extent, Southern Power's 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 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, Southern Company Gas, or Southern Power, the respective subsidiaries have financial obligations and, with respect to Southern Company and Southern Company Gas, regulatory restrictions that must be satisfied, including among others, debt service and preferred stock dividends. These subsidiaries are separate legal entities and, except as described below, have no obligation to provide Southern Company, Southern Company Gas, or Southern Power with funds. Certain of Southern Power's assets are held through controlling interests in subsidiaries. In certain cases, distributions without partner consent are limited to available cash, and the subsidiaries are obligated to distribute all available cash to their owners each quarter. In addition, Southern Company, Southern Company Gas, and Southern Power 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 as 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 that Southern Power 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, SEGCO, 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, SEGCO, 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, SEGCO, 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, SEGCO, 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, SEGCO, 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, SEGCO, 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, including further interpretation and guidance on tax reform;

- volatility in market prices for electricity and natural gas;
- actual or threatened cyber or physical 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.

Georgia Power's ability to make future borrowings through its term loan credit facility with the FFB 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, SEGCO, Southern Company Gas Capital, or Nicor Gas to execute future borrowings.

The debt and credit agreements of the registrants, SEGCO, 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 funding available for 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, government regulations, and/or 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 funding available for 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, actual or threatened physical or cyber attacks, 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 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 further into the

future. 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 as, or may not be 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, 2018, goodwill was $5.3 billion and $5.0 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.

Item 1B. UNRESOLVED STAFF COMMENTS.

None.

Item 2. PROPERTIES

Electric

Electric Properties

The traditional electric operating companies, Southern Power, and SEGCO, at January 1, 2019, owned and/or operated 33 hydroelectric generating stations, 26 fossil fuel generating stations, three nuclear generating stations, 13 combined cycle/ cogeneration stations, 40 solar facilities, nine wind facilities, and one biomass facility. The amounts of capacity for each company, at January 1, 2019, 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	(2)
Barry	Mobile, AL	1,300,000	
Greene County	Demopolis, AL	300,000	(3)
Gaston Unit 5	Wilsonville, AL	880,000	
Miller	Birmingham, AL	2,532,288	(4)
Alabama Power Total		6,153,538	
Bowen	Cartersville, GA	3,160,000	
Hammond	Rome, GA	800,000	(5)
McIntosh	Effingham County, GA	163,117	(5)
Scherer	Macon, GA	750,924	(6)
Wansley	Carrollton, GA	925,550	(7)
Yates	Newnan, GA	700,000	
Georgia Power Total		6,499,591	
Daniel	Pascagoula, MS	500,000	(8)
Greene County	Demopolis, AL	200,000	(3)
Watson	Gulfport, MS	750,000	
Mississippi Power Total		1,450,000	
Gaston Units 1-4	Wilsonville, AL		
SEGCO Total		1,000,000	(9)
Total Fossil Steam		15,103,129	
NUCLEAR STEAM			
Farley	Dothan, AL		
Alabama Power Total		1,720,000	
Hatch	Baxley, GA	899,612	(10)
Vogtle Units 1 and 2	Augusta, GA	1,060,240	(11)
Georgia Power Total		1,959,852	
Total Nuclear Steam		3,679,852	

Generating Station	Location	Nameplate Capacity (1)	
COMBUSTION TURBINES			
Greene County	Demopolis, AL		
Alabama Power Total		720,000	
Boulevard	Savannah, GA	19,700	
McDonough Unit 3	Atlanta, GA	78,800	
McIntosh Units 1 through 8	Effingham County, GA	640,000	
McManus	Brunswick, GA	481,700	
Robins	Warner Robins, GA	158,400	
Wansley	Carrollton, GA	26,322	(7)
Wilson	Augusta, GA	354,100	
Georgia Power Total		1,759,022	
Chevron Cogenerating Station	Pascagoula, MS	147,292	(12)
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	
Rowan	Salisbury, NC	455,250	
Southern Power Total		2,600,050	
Gaston **(SEGCO)**	Wilsonville, AL	19,680	(9)
Total Combustion Turbines		5,324,804	
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 and 11	Effingham County, GA	1,318,920	
McDonough-Atkinson Units 4 through 6	Atlanta, GA	2,520,000	
Georgia Power Total		3,838,920	
Daniel	Pascagoula, MS	1,070,424	
Ratcliffe	Kemper County, MS	769,898	(13)
Mississippi Power Total		1,840,322	
Franklin	Smiths, AL	1,857,820	
Harris	Autaugaville, AL	1,318,920	
Mankato	Mankato, MN	375,000	(14)
Rowan	Salisbury, NC	530,550	
Wansley Units 6 and 7	Carrollton, GA	1,073,000	
Southern Power Total		5,155,290	
Total Combined Cycle		11,904,956	

Generating Station	Location	Nameplate Capacity (1)	
HYDROELECTRIC FACILITIES			
Bankhead	Holt, AL	53,985	
Bouldin	Wetumpka, AL	225,000	
Harris	Wedowee, AL	132,000	
Henry	Ohatchee, AL	72,900	
Holt	Holt, AL	46,944	
Jordan	Wetumpka, AL	100,000	
Lay	Clanton, AL	177,000	
Lewis Smith	Jasper, AL	157,500	
Logan Martin	Vincent, AL	135,000	
Martin	Dadeville, AL	182,000	
Mitchell	Verbena, AL	170,000	
Thurlow	Tallassee, AL	81,000	
Weiss	Leesburg, AL	87,750	
Yates	Tallassee, AL	47,000	
Alabama Power Total		1,668,079	
Bartletts Ferry	Columbus, GA	173,000	
Goat Rock	Columbus, GA	38,600	
Lloyd Shoals	Jackson, GA	14,400	
Morgan Falls	Atlanta, GA	16,800	
North Highlands	Columbus, GA	29,600	
Oliver Dam	Columbus, GA	60,000	
Rocky Mountain	Rome, GA	215,256	(15)
Sinclair Dam	Milledgeville, GA	45,000	
Tallulah Falls	Clayton, GA	72,000	
Terrora	Clayton, GA	16,000	
Tugalo	Clayton, GA	45,000	
Wallace Dam	Eatonton, GA	321,300	
Yonah	Toccoa, GA	22,500	
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 Rucker	Calhoun County, AL	10,560	
Anniston Army Depot	Dale County, AL	7,380	
Alabama Power Total		17,940	
Fort Benning	Columbus, GA	30,005	
Fort Gordon	Augusta, GA	30,000	
Fort Stewart	Fort Stewart, GA	30,000	
Kings Bay	Camden County, GA	30,161	
Dalton	Dalton, GA	6,508	
Marine Corps Logistics Base	Albany, GA	31,161	
4 Other Plants	Various Georgia locations	5,171	
Georgia Power Total		163,006	
Adobe	Kern County, CA	20,000	
Apex	North Las Vegas, NV	20,000	
Boulder I	Clark County, NV	100,000	
Butler	Taylor County, GA	103,700	
Butler Solar Farm	Taylor County, GA	22,000	
Calipatria	Imperial County, CA	20,000	
Campo Verde	Imperial County, CA	147,420	
Cimarron	Springer, NM	30,640	
Decatur County	Decatur County, GA	20,000	
Decatur Parkway	Decatur County, GA	84,000	
Desert Stateline	San Bernadino County, CA	299,900	
East Pecos	Pecos County, TX	120,000	
Garland	Kern County, CA	205,130	
Gaskell West I	Kern County, CA	20,000	
Granville	Oxford, NC	2,500	
Henrietta	Kings County, CA	102,000	
Imperial Valley	Imperial County, CA	163,200	
Lamesa	Dawson County, TX	102,000	
Lost Hills - Blackwell	Kern County, CA	33,440	
Macho Springs	Luna County, NM	55,000	
Morelos del Sol	Kern County, CA	15,000	
North Star	Fresno County, CA	61,600	
Pawpaw	Taylor County, GA	30,480	
Roserock	Pecos County, TX	160,000	
Rutherford	Rutherford County, NC	74,800	
Sandhills	Taylor County, GA	146,890	
Spectrum	Clark County, NV	30,240	
Tranquillity	Fresno County, CA	205,300	
Southern Power Total		2,395,240	(16)
Total Solar		2,576,186	

Generating Station	Location	Nameplate Capacity (1)	
WIND FACILITIES			
Bethel	Castro County, TX	276,000	
Cactus Flats	Concho County, TX	148,350	
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	
Southern Power Total		1,622,080	(17)
BIOMASS FACILITY			
Nacogdoches	Sacul, TX		
Southern Power Total		115,500	
Total Alabama Power Generating Capacity		11,814,627	
Total Georgia Power Generating Capacity		15,307,927	
Total Mississippi Power Generating Capacity		3,516,374	
Total Southern Power Generating Capacity		11,888,160	
Total Generating Capacity		43,546,768	

Notes:

(1) See "Jointly-Owned Facilities" herein and Note 5 to the financial statements under "Joint Ownership Agreements" in Item 8 herein for additional information.

(2) As part of its environmental compliance strategy, Alabama Power plans to retire Plant Gorgas Units 8, 9, and 10 by April 15, 2019. See Note 2 to the financial statements under "Alabama Power – Environmental Accounting Order" in Item 8 herein for additional information.

(3) Owned by Alabama Power and Mississippi Power as tenants in common in the proportions of 60% and 40%, respectively. Capacity shown for each company represents its portion of total plant capacity.

(4) Capacity shown is Alabama Power's portion (95.92%) of total plant capacity.

(5) Georgia Power has requested to decertify and retire Plant Hammond Units 1 through 4 and Plant McIntosh Unit 1 upon approval of its 2019 IRP filing. See Note 2 to the financial statements under "Georgia Power – Integrated Resource Plan" in Item 8 herein for additional information.

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

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

(8) Capacity shown is Mississippi Power's portion (50%) of total plant capacity.

(9) SEGCO is jointly-owned by Alabama Power and Georgia Power. See BUSINESS in Item 1 herein for additional information. Also see Note 7 to the financial statements under "SEGCO" in Item 8 herein.

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

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

(12) Generation is dedicated to a single industrial customer. See MANAGEMENT'S DISCUSSION AND ANALYSIS – FINANCIAL CONDITION AND LIQUIDITY – "Credit Rating Risk" of Mississippi Power in Item 7 herein.

(13) The capacity shown is the gross capacity using natural gas fuel without supplemental firing.

(14) On November 5, 2018, Southern Power entered into an agreement with Northern States Power to sell all of its equity interests in Plant Mankato (including the 385-MW expansion currently under construction). The ultimate outcome of this matter cannot be determined at this time. See Note 15 to the financial statements under "Southern Power – Sales of Natural Gas Plants" in Item 8 herein for additional information.

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

(16) In May 2018, Southern Power sold a noncontrolling 33% equity interest in SP Solar (a limited partnership indirectly owning all of Southern Power's solar facilities, except the Roserock and Gaskell West facilities). SP Solar is the 51% majority owner of Boulder 1, Garland, Henrietta, Imperial Valley, Lost Hills Blackwell, North Star, and Tranquillity; the 66% majority owner of Desert Stateline; and the sole owner of the remaining SP Solar facilities. Southern Power is the 51% majority owner of Roserock and also the controlling partner in a tax equity partnership owning Gaskell West. All of these entities are consolidated subsidiaries of Southern Power and the capacity shown in the table is 100% of the nameplate capacity for the respective facility.

(17) In December 2018, Southern Power sold a noncontrolling tax equity interest in SP Wind (which owns all of Southern Power's wind facilities, except Cactus Flats). SP Wind is the 90.1% majority owner of Wake Wind and owns 100% of the remaining SP Wind facilities. Southern Power is the controlling partner in a tax equity partnership owning Cactus Flats. All of these entities are consolidated subsidiaries of Southern Power and the capacity shown in the table is 100% of the nameplate capacity for the respective facility.

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 extends from Plant Daniel to the Louisiana state line. Entergy Gulf States Louisiana, LLC is paying a use fee over a 40-year period through 2024 covering all expenses and the amortization of the original cost. At December 31, 2018, the unamortized portion was approximately $12 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. 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. As a result of the abandonment of the Kemper IGCC, final mine reclamation began in 2018 and is expected to be substantially completed in 2020, with monitoring expected to continue through 2027. Mississippi Power is currently evaluating its options regarding the final disposition of the CO_2 pipeline, including removal of the pipeline. This evaluation is expected to be complete later in 2019. The ultimate outcome of these matters cannot be determined at this time. See Note 2 to the financial statements under "Mississippi Power – Kemper County Energy Facility – Lignite Mine and CO_2 Pipeline Facilities" in Item 8 herein for additional information on the lignite mine and CO_2 pipeline.

In August 2018, Mississippi Power filed a RMP which identified alternatives that, if implemented, could impact Mississippi Power's generating stations as well as Plant Greene County, jointly owned by Mississippi Power and Alabama Power. See BUSINESS in Item 1 herein under "Rate Matters – Integrated Resource Planning – Mississippi Power" for additional information.

In conjunction with Southern Company's sale of Gulf Power, Mississippi Power and Gulf Power have committed to seek a restructuring of their 50% undivided ownership interests in Plant Daniel such that each of them would, after the restructuring, own 100% of a generating unit. On January 15, 2019, Gulf Power provided notice to Mississippi Power that Gulf Power will retire its share of the generating capacity of Plant Daniel on January 15, 2024. Mississippi Power has the option to purchase Gulf Power's ownership interest for $1 on January 15, 2024, provided that Mississippi Power exercises the option no later than 120 days prior to that date. Mississippi Power is assessing the potential operational and economic effects of Gulf Power's notice. The ultimate outcome of these matters remains subject to completion of Mississippi Power's evaluations and applicable regulatory approvals, including the FERC and the Mississippi PSC, and cannot now be determined. See Note 15 to the financial statements under "Southern Company's Sale of Gulf Power" in Item 8 herein for information regarding the sale of Gulf Power.

In 2018, the maximum demand on the traditional electric operating companies, Southern Power Company, and SEGCO was 36,429,000 KWs and occurred on January 18, 2018. The all-time maximum demand of 38,777,000 KWs on the traditional electric operating companies, Southern Power Company, 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 Company, and SEGCO in 2018 was 29.8%. See SELECTED FINANCIAL DATA in Item 6 herein for additional information.

Jointly-Owned Facilities

Alabama Power, Georgia Power, and Mississippi Power at January 1, 2019 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	Alabama Power	Power South	Georgia Power	Mississippi Power	OPC	MEAG Power	Dalton	Gulf Power
	(MWs)								
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 Scherer Unit 3	818	—	—	75.0	—	—	—	—	25.0
Plant Wansley	1,779	—	—	53.5	—	30.0	15.1	1.4	—
Rocky Mountain	903	—	—	25.4	—	74.6	—	—	—
Plant Daniel Units 1 and 2	1,000	—	—	—	50.0	—	—	—	50.0

Alabama Power, Georgia Power, and Mississippi 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. 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 9 to the financial statements under "Fuel and Power Purchase 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 2 to the financial statements under "Georgia Power – Nuclear Construction" in Item 8 herein.

On December 4, 2018, Southern Power completed the sale of its 65% ownership interest in Plant Stanton Unit A, which Southern Power previously jointly-owned with OUC, FMPA, and KUA, to NextEra Energy. See Note 15 to the financial statements under "Southern Power – Sales of Natural Gas Plants" in Item 8 herein for additional information.

Titles to Property

The traditional electric operating companies', Southern Power's, and SEGCO's interests in the principal plants and other important units of the respective companies are owned in fee by such companies, subject to the following major encumbrances: (1) liens pursuant to the assumption of debt obligations by Mississippi Power in connection with the acquisition of Plant Daniel Units 3 and 4, (2) a leasehold interest granted by Mississippi Power's largest retail customer, Chevron Products Company (Chevron), at the Chevron refinery, on which five combustion turbines of Mississippi Power are located, (3) liens pursuant to the agreements entered into with Chevron in October 2017 on Mississippi Power's 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 Plant Mankato in 2016 by Southern Power Company. See Note 5 to the financial statements under "Assets Subject to Lien," Note 8 to the financial statements under "Secured Debt" and "Long-term Debt – DOE Loan Guarantee Borrowings," and Note 15 to the financial statements under "Southern Power – Sales of Natural Gas Plants" 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 and Note 5 to the financial statements under "Joint Ownership Agreements" in Item 8 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 8 to the financial statements under "Long-term Debt – Other Long-Term Debt – Southern Company Gas" 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, 2018, Southern Company Gas' gas distribution operations segment owned approximately 75,200 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 fields in Illinois with a total working capacity of approximately 150 Bcf, approximately 135 Bcf of which is usually 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 four LNG plants located in Georgia and Tennessee with total LNG storage capacity of approximately 7.4 Bcf. In addition, Southern Company Gas owns two propane storage facilities in Virginia, each 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 included in the all other 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" of Southern Company Gas in Item 7 herein and Note 3 to the financial statements under "Other Matters – Southern Company Gas" in Item 8 herein for additional information.

Jointly-Owned Properties – Southern Company Gas' gas pipeline investments segment has a 50% undivided ownership interest in a 115-mile pipeline facility in northwest Georgia that was placed in service in August 2017. Southern Company Gas also has an agreement to lease its 50% undivided ownership in the pipeline facility. See Note 5 to the financial statements under "Joint Ownership Agreements" in Item 8 herein for additional information.

Southern Company Gas owns a 50% interest in a LNG liquefaction and storage facility in Jacksonville, Florida, which was placed in service in October 2018 and is included in the all other segment. The facility is outfitted with a 2.0 million gallon storage tank with the capacity to produce in excess of 120,000 gallons of LNG per day.

Item 3. LEGAL PROCEEDINGS

See Note 3 to the financial statements 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, 2018.

Thomas A. Fanning
Chairman, President, and Chief Executive Officer
Age 61
First elected in 2003. Chairman and Chief Executive Officer since December 2010 and President since August 2010.

Andrew W. Evans
Executive Vice President and Chief Financial Officer
Age 52
First elected in 2016. Executive Vice President since July 2016 and Chief Financial Officer since June 2018. Previously served as Chief Executive Officer and Chairman of Southern Company Gas' Board of Directors from January 2016 through June 2018, President of Southern Company Gas from May 2015 through June 2018, 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.

W. Paul Bowers
Chairman, President and Chief Executive Officer of Georgia Power
Age 62
First elected in 2001. 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.
Executive Vice President of SCS
Age 49
First elected in 2012. Executive Vice President for Operations of SCS since June 2018. Previously served as President, Chief Executive Officer, and Director of Gulf Power from July 2012 through December 2018 and Chairman of Gulf Power's Board of Directors from July 2015 through December 2018.

Mark A. Crosswhite
Chairman, President and Chief Executive Officer of Alabama Power
Age 56
First elected in 2010. 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.

Kimberly S. Greene
Chairman, President, and Chief Executive Officer of Southern Company Gas
Age 52
First elected in 2013. Chairman, President, and Chief Executive Officer of Southern Company Gas since June 2018. Director of Southern Company Gas since July 2016. Previously served as Executive Vice President and Chief Operating Officer of Southern Company from March 2014 through June 2018 and President and Chief Executive Officer of SCS from April 2013 through February 2014.

James Y. Kerr II
Executive Vice President, Chief Legal Officer, and Chief Compliance Officer
Age 54
First elected in 2014. Executive Vice President, Chief Legal Officer (formerly known as General Counsel), and Chief Compliance Officer since March 2014. 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 56
First elected in 2011. Chairman, President, and Chief Executive Officer of Southern Nuclear since July 2011.

Mark S. Lantrip
Executive Vice President
Age 64
First elected in 2014. Executive Vice President since February 2019. Chairman, President, and Chief Executive Officer of SCS since March 2014 and Chairman, President, and Chief Executive Officer of Southern Power since March 2018. Previously served as Treasurer of Southern Company from October 2007 to February 2014 and Executive Vice President of SCS from November 2010 to March 2014.

Anthony L. Wilson
Chairman, President, and Chief Executive Officer of Mississippi Power
Age 54
First 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 60
First 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 23, 2018, for a term of one year or until their successors are elected and have qualified, except for Mr. Lantrip, whose election as Executive Vice President was effective February 11, 2019.

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, 2018.

Mark A. Crosswhite
Chairman, President, and Chief Executive Officer
Age 56
First 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 55
First 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 59
First elected in 2010. Executive Vice President, Chief Financial Officer, and Treasurer since August 2010.

Zeke W. Smith
Executive Vice President
Age 59
First elected in 2010. Executive Vice President of External Affairs since November 2010.

James P. Heilbron
Senior Vice President and Senior Production Officer
Age 47
First elected in 2013. Senior Vice President and Senior Production Officer of Alabama Power since March 2013 and Senior Vice President and Senior Production Officer – West of SCS and Senior Production Officer of Mississippi Power since October 2018.

R. Scott Moore
Senior Vice President
Age 51
First 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 27, 2018 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 under the ticker symbol SO. The common stock is also traded on regional exchanges across the U.S.

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, 2019: 115,847

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

(a)(3) 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

	Page
Southern Company	II-3
Alabama Power	II-6
Georgia Power	II-8
Mississippi Power	II-10
Southern Power	II-12
Southern Company Gas	II-13

SELECTED CONSOLIDATED FINANCIAL AND OPERATING DATA 2014-2018
Southern Company and Subsidiary Companies 2018 Annual Report

	2018	2017	2016[d]	2015	2014
Operating Revenues (in millions)	**$ 23,495**	$ 23,031	$ 19,896	$ 17,489	$ 18,467
Total Assets (in millions)[a]	**$ 116,914**	$ 111,005	$ 109,697	$ 78,318	$ 70,233
Gross Property Additions (in millions)	**$ 8,205**	$ 5,984	$ 7,624	$ 6,169	$ 6,522
Return on Average Common Equity (percent)[b]	**9.11**	3.44	10.80	11.68	10.08
Cash Dividends Paid Per Share of Common Stock	**$ 2.3800**	$ 2.3000	$ 2.2225	$ 2.1525	$ 2.0825
Consolidated Net Income Attributable to Southern Company (in millions)[b]	**$ 2,226**	$ 842	$ 2,448	$ 2,367	$ 1,963
Earnings Per Share —					
Basic	**$ 2.18**	$ 0.84	$ 2.57	$ 2.60	$ 2.19
Diluted	**2.17**	0.84	2.55	2.59	2.18
Capitalization (in millions):					
Common stockholders' equity	**$ 24,723**	$ 24,167	$ 24,758	$ 20,592	$ 19,949
Preferred and preference stock of subsidiaries and noncontrolling interests	**4,316**	1,361	1,854	1,390	977
Redeemable preferred stock of subsidiaries	**291**	324	118	118	375
Redeemable noncontrolling interests	**—**	—	164	43	39
Long-term debt[a][c]	**40,736**	44,462	42,629	24,688	20,644
Total (excluding amounts due within one year)[c]	**$ 70,066**	$ 70,314	$ 69,523	$ 46,831	$ 41,984
Capitalization Ratios (percent):					
Common stockholders' equity	**35.3**	34.4	35.6	44.0	47.5
Preferred and preference stock of subsidiaries and noncontrolling interests	**6.2**	1.9	2.7	3.0	2.3
Redeemable preferred stock of subsidiaries	**0.4**	0.5	0.2	0.3	0.9
Redeemable noncontrolling interests	**—**	—	0.2	0.1	0.1
Long-term debt[a][c]	**58.1**	63.2	61.3	52.6	49.2
Total (excluding amounts due within one year)[c]	**100.0**	100.0	100.0	100.0	100.0
Other Common Stock Data:					
Book value per share	**$ 23.91**	$ 23.99	$ 25.00	$ 22.59	$ 21.98
Market price per share:					
High	**$ 49.43**	$ 53.51	$ 54.64	$ 53.16	$ 51.28
Low	**42.38**	46.71	46.00	41.40	40.27
Close (year-end)	**43.92**	48.09	49.19	46.79	49.11
Market-to-book ratio (year-end) (percent)	**183.7**	200.5	196.8	207.2	223.4
Price-earnings ratio (year-end) (times)	**20.1**	57.3	19.1	18.0	22.4
Dividends paid (in millions)	**$ 2,425**	$ 2,300	$ 2,104	$ 1,959	$ 1,866
Dividend yield (year-end) (percent)	**5.4**	4.8	4.5	4.6	4.2
Dividend payout ratio (percent)	**108.9**	273.2	86.0	82.7	95.0
Shares outstanding (in thousands):					
Average	**1,020,247**	1,000,336	951,332	910,024	897,194
Year-end	**1,033,788**	1,007,603	990,394	911,721	907,777
Stockholders of record (year-end)	**116,135**	120,803	126,338	131,771	137,369

(a) A reclassification of debt issuance costs from Total Assets to Long-term debt of $202 million and a reclassification of deferred tax assets from Total Assets to Accumulated deferred income taxes of $488 million is reflected for 2014, in accordance with new accounting standards adopted in 2015 and applied retrospectively.

(b) Georgia Power recorded a pre-tax estimated probable loss of $1.1 billion ($0.8 billion after tax) in the second quarter 2018 to reflect its revised estimate to complete construction and start-up of Plant Vogtle Units 3 and 4. In addition, 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. See Note 2 to the financial statements in Item 8 herein for additional information.

(c) Amounts related to Gulf Power have been reclassified to liabilities held for sale at December 31, 2018. See Note 15 to the financial statements under "Southern Company's Sale of Gulf Power" in Item 8 herein for additional information.

(d) 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 15 to the financial statements under "Southern Company Merger with Southern Company Gas" in Item 8 herein for additional information.

SELECTED CONSOLIDATED FINANCIAL AND OPERATING DATA 2014-2018 (continued)
Southern Company and Subsidiary Companies 2018 Annual Report

	2018	2017	2016[a]	2015	2014
Operating Revenues (in millions):					
Residential	**$ 6,608**	$ 6,515	$ 6,614	$ 6,383	$ 6,499
Commercial	**5,266**	5,439	5,394	5,317	5,469
Industrial	**3,224**	3,262	3,171	3,172	3,449
Other	**124**	114	55	115	133
Total retail	**15,222**	15,330	15,234	14,987	15,550
Wholesale	**2,516**	2,426	1,926	1,798	2,184
Total revenues from sales of electricity	**17,738**	17,756	17,160	16,785	17,734
Natural gas revenues	**3,854**	3,791	1,596	—	—
Other revenues	**1,903**	1,484	1,140	704	733
Total	**$ 23,495**	$ 23,031	$ 19,896	$ 17,489	$ 18,467
Kilowatt-Hour Sales (in millions):					
Residential	**54,590**	50,536	53,337	52,121	53,347
Commercial	**53,451**	52,340	53,733	53,525	53,243
Industrial	**53,341**	52,785	52,792	53,941	54,140
Other	**799**	846	883	897	909
Total retail	**162,181**	156,507	160,745	160,484	161,639
Wholesale sales	**49,963**	49,034	37,043	30,505	32,786
Total	**212,144**	205,541	197,788	190,989	194,425
Average Revenue Per Kilowatt-Hour (cents):					
Residential	**12.10**	12.89	12.40	12.25	12.18
Commercial	**9.85**	10.39	10.04	9.93	10.27
Industrial	**6.04**	6.18	6.01	5.88	6.37
Total retail	**9.39**	9.80	9.48	9.34	9.62
Wholesale	**5.04**	4.95	5.20	5.89	6.66
Total sales	**8.36**	8.64	8.68	8.79	9.12
Average Annual Kilowatt-Hour					
Use Per Residential Customer	**12,514**	11,618	12,387	13,318	13,765
Average Annual Revenue					
Per Residential Customer	**$ 1,555**	$ 1,498	$ 1,541	$ 1,630	$ 1,679
Plant Nameplate Capacity					
Ratings (year-end) (megawatts)	**45,824**	46,936	46,291	44,223	46,549
Maximum Peak-Hour Demand (megawatts):					
Winter	**36,429**	31,956	32,272	36,794	37,234
Summer	**34,841**	34,874	35,781	36,195	35,396
System Reserve Margin (at peak) (percent)	**29.8**	30.8	34.2	33.2	19.8
Annual Load Factor (percent)	**61.2**	61.4	61.5	59.9	59.6
Plant Availability (percent):					
Fossil-steam	**81.4**	84.5	86.4	86.1	85.8
Nuclear	**94.0**	94.7	93.3	93.5	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 15 to the financial statements under "Southern Company Merger with Southern Company Gas" in Item 8 herein for additional information.

SELECTED CONSOLIDATED FINANCIAL AND OPERATING DATA 2014-2018 (continued)
Southern Company and Subsidiary Companies 2018 Annual Report

	2018	2017	2016[a]	2015	2014
Source of Energy Supply (percent):					
Gas	**41.6**	41.9	41.7	42.7	37.0
Coal	**27.0**	27.0	30.3	32.3	39.3
Nuclear	**13.8**	14.5	14.5	15.2	14.8
Hydro	**2.9**	2.1	2.1	2.6	2.5
Other	**5.4**	5.4	2.4	0.8	0.4
Purchased power	**9.3**	9.1	9.0	6.4	6.0
Total	**100.0**	100.0	100.0	100.0	100.0
Gas Sales Volumes (mmBtu in millions):					
Firm	**791**	729	296	—	—
Interruptible	**109**	109	53	—	—
Total	**900**	838	349	—	—
Traditional Electric Operating Company Customers (year-end) (in thousands):					
Residential	**4,053**	4,011	3,970	3,928	3,890
Commercial[b]	**603**	599	595	590	586
Industrial[b]	**17**	18	17	17	17
Other	**12**	12	11	11	11
Total electric customers	**4,685**	4,640	4,593	4,546	4,504
Gas distribution operations customers	**4,248**	4,623	4,586	—	—
Total utility customers	**8,933**	9,263	9,179	4,546	4,504
Employees (year-end)	**30,286**	31,344	32,015	26,703	26,369

(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 15 to the financial statements under "Southern Company Merger with Southern Company Gas" in Item 8 herein for additional information.

(b) A reclassification of customers from commercial to industrial is reflected for years 2014-2015 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 2014-2018
Alabama Power Company 2018 Annual Report

	2018	2017	2016	2015	2014
Operating Revenues (in millions)	**$ 6,032**	$ 6,039	$ 5,889	$ 5,768	$ 5,942
Net Income After Dividends on Preferred and Preference Stock (in millions)	**$ 930**	$ 848	$ 822	$ 785	$ 761
Cash Dividends on Common Stock (in millions)	**$ 801**	$ 714	$ 765	$ 571	$ 550
Return on Average Common Equity (percent)	**13.00**	12.89	13.34	13.37	13.52
Total Assets (in millions)(*)	**$ 26,730**	$ 23,864	$ 22,516	$ 21,721	$ 20,493
Gross Property Additions (in millions)	**$ 2,273**	$ 1,949	$ 1,338	$ 1,492	$ 1,543
Capitalization (in millions):					
Common stockholder's equity	**$ 7,477**	$ 6,829	$ 6,323	$ 5,992	$ 5,752
Preference stock	**—**	—	196	196	343
Redeemable preferred stock	**291**	291	85	85	342
Long-term debt(*)	**7,923**	7,628	6,535	6,654	6,137
Total (excluding amounts due within one year)	**$ 15,691**	$ 14,748	$ 13,139	$ 12,927	$ 12,574
Capitalization Ratios (percent):					
Common stockholder's equity	**47.7**	46.3	48.1	46.4	45.8
Preference stock	**—**	—	1.5	1.5	2.7
Redeemable preferred stock	**1.9**	2.0	0.7	0.7	2.7
Long-term debt(*)	**50.4**	51.7	49.7	51.4	48.8
Total (excluding amounts due within one year)	**100.0**	100.0	100.0	100.0	100.0
Customers (year-end):					
Residential	**1,273,526**	1,268,271	1,262,752	1,253,875	1,247,061
Commercial	**200,032**	199,840	199,146	197,920	197,082
Industrial	**6,158**	6,171	6,090	6,056	6,032
Other	**760**	766	762	757	753
Total	**1,480,476**	1,475,048	1,468,750	1,458,608	1,450,928
Employees (year-end)	**6,650**	6,613	6,805	6,986	6,935

(*) A reclassification of debt issuance costs from Total Assets to Long-term debt of $40 million and a reclassification of deferred tax assets from Total Assets to Accumulated deferred income taxes of $20 million is reflected for 2014, in accordance with new accounting standards adopted in 2015 and applied retrospectively.

SELECTED FINANCIAL AND OPERATING DATA 2014-2018 (continued)
Alabama Power Company 2018 Annual Report

	2018	2017	2016	2015	2014
Operating Revenues (in millions):					
Residential	**$ 2,335**	$ 2,302	$ 2,322	$ 2,207	$ 2,209
Commercial	**1,578**	1,649	1,627	1,564	1,533
Industrial	**1,428**	1,477	1,416	1,436	1,480
Other	**26**	30	(43)	27	27
Total retail	**5,367**	5,458	5,322	5,234	5,249
Wholesale — non-affiliates	**279**	276	283	241	281
Wholesale — affiliates	**119**	97	69	84	189
Total revenues from sales of electricity	**5,765**	5,831	5,674	5,559	5,719
Other revenues	**267**	208	215	209	223
Total	**$ 6,032**	$ 6,039	$ 5,889	$ 5,768	$ 5,942
Kilowatt-Hour Sales (in millions):					
Residential	**18,626**	17,219	18,343	18,082	18,726
Commercial	**13,868**	13,606	14,091	14,102	14,118
Industrial	**23,006**	22,687	22,310	23,380	23,799
Other	**187**	198	208	201	211
Total retail	**55,687**	53,710	54,952	55,765	56,854
Wholesale — non-affiliates	**5,018**	5,415	5,744	3,567	3,588
Wholesale — affiliates	**4,565**	4,166	3,177	4,515	6,713
Total	**65,270**	63,291	63,873	63,847	67,155
Average Revenue Per Kilowatt-Hour (cents):					
Residential	**12.54**	13.37	12.66	12.21	11.80
Commercial	**11.38**	12.12	11.55	11.09	10.86
Industrial	**6.21**	6.51	6.35	6.14	6.22
Total retail	**9.64**	10.16	9.68	9.39	9.23
Wholesale	**4.15**	3.89	3.95	4.02	4.56
Total sales	**8.83**	9.21	8.88	8.71	8.52
Residential Average Annual Kilowatt-Hour Use Per Customer	**14,660**	13,601	14,568	14,454	15,051
Residential Average Annual Revenue Per Customer	**$ 1,878**	$ 1,819	$ 1,844	$ 1,764	$ 1,775
Plant Nameplate Capacity Ratings (year-end) (megawatts)	**11,815**	11,797	11,797	11,797	12,222
Maximum Peak-Hour Demand (megawatts):					
Winter	**11,744**	10,513	10,282	12,162	11,761
Summer	**10,652**	10,711	10,932	11,292	11,054
Annual Load Factor (percent)	**60.1**	63.5	63.5	58.4	61.4
Plant Availability (percent):					
Fossil-steam	**81.6**	82.8	83.0	81.5	82.5
Nuclear	**91.6**	97.6	88.0	92.1	93.3
Source of Energy Supply (percent):					
Coal	**43.8**	44.8	47.1	49.1	49.0
Nuclear	**20.5**	22.2	20.3	21.3	20.7
Gas	**17.2**	18.1	17.1	14.6	15.4
Hydro	**6.7**	5.4	4.8	5.6	5.5
Purchased power —					
From non-affiliates	**5.4**	4.6	4.8	4.4	3.6
From affiliates	**6.4**	4.9	5.9	5.0	5.8
Total	**100.0**	100.0	100.0	100.0	100.0

SELECTED FINANCIAL AND OPERATING DATA 2014-2018
Georgia Power Company 2018 Annual Report

	2018	2017	2016	2015	2014
Operating Revenues (in millions)	**$ 8,420**	$ 8,310	$ 8,383	$ 8,326	$ 8,988
Net Income After Dividends on Preferred and Preference Stock (in millions)[a]	**$ 793**	$ 1,414	$ 1,330	$ 1,260	$ 1,225
Cash Dividends on Common Stock (in millions)	**$ 1,396**	$ 1,281	$ 1,305	$ 1,034	$ 954
Return on Average Common Equity (percent)	**6.04**	12.15	12.05	11.92	12.24
Total Assets (in millions)[b]	**$ 40,365**	$ 36,779	$ 34,835	$ 32,865	$ 30,872
Gross Property Additions (in millions)	**$ 3,176**	$ 1,080	$ 2,314	$ 2,332	$ 2,146
Capitalization (in millions):					
Common stockholder's equity	**$ 14,323**	$ 11,931	$ 11,356	$ 10,719	$ 10,421
Preferred and preference stock	**—**	—	266	266	266
Long-term debt[b]	**9,364**	11,073	10,225	9,616	8,563
Total (excluding amounts due within one year)	**$ 23,687**	$ 23,004	$ 21,847	$ 20,601	$ 19,250
Capitalization Ratios (percent):					
Common stockholder's equity	**60.5**	51.9	52.0	52.0	54.1
Preferred and preference stock	**—**	—	1.2	1.3	1.4
Long-term debt[b]	**39.5**	48.1	46.8	46.7	44.5
Total (excluding amounts due within one year)	**100.0**	100.0	100.0	100.0	100.0
Customers (year-end):					
Residential	**2,220,240**	2,185,782	2,155,945	2,127,658	2,102,673
Commercial[c]	**312,474**	308,939	305,488	302,891	300,186
Industrial[c]	**10,571**	10,644	10,537	10,429	10,192
Other	**9,838**	9,766	9,585	9,261	9,003
Total	**2,553,123**	2,515,131	2,481,555	2,450,239	2,422,054
Employees (year-end)	**6,967**	6,986	7,527	7,989	7,909

(a) Georgia Power recorded a pre-tax estimated probable loss of $1.1 billion ($0.8 billion after tax) in the second quarter 2018 to reflect its revised estimate to complete construction and start-up of Plant Vogtle Units 3 and 4.

(b) A reclassification of debt issuance costs from Total Assets to Long-term debt of $124 million and a reclassification of deferred tax assets from Total Assets to Accumulated deferred income taxes of $34 million is reflected for 2014, 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 2014-2015 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 2014-2018 (continued)
Georgia Power Company 2018 Annual Report

	2018	2017	2016	2015	2014
Operating Revenues (in millions):					
Residential	**$ 3,301**	$ 3,236	$ 3,318	$ 3,240	$ 3,350
Commercial	**3,023**	3,092	3,077	3,094	3,271
Industrial	**1,344**	1,321	1,291	1,305	1,525
Other	**84**	89	86	88	94
Total retail	**7,752**	7,738	7,772	7,727	8,240
Wholesale — non-affiliates	**163**	163	175	215	335
Wholesale — affiliates	**24**	26	42	20	42
Total revenues from sales of electricity	**7,939**	7,927	7,989	7,962	8,617
Other revenues	**481**	383	394	364	371
Total	**$ 8,420**	$ 8,310	$ 8,383	$ 8,326	$ 8,988
Kilowatt-Hour Sales (in millions):					
Residential	**28,331**	26,144	27,585	26,649	27,132
Commercial	**32,958**	32,155	32,932	32,719	32,426
Industrial	**23,655**	23,518	23,746	23,805	23,549
Other	**549**	584	610	632	633
Total retail	**85,493**	82,401	84,873	83,805	83,740
Wholesale — non-affiliates	**3,140**	3,277	3,415	3,501	4,323
Wholesale — affiliates	**526**	800	1,398	552	1,117
Total	**89,159**	86,478	89,686	87,858	89,180
Average Revenue Per Kilowatt-Hour (cents):					
Residential	**11.65**	12.38	12.03	12.16	12.35
Commercial	**9.17**	9.62	9.34	9.46	10.09
Industrial	**5.68**	5.62	5.44	5.48	6.48
Total retail	**9.07**	9.39	9.16	9.22	9.84
Wholesale	**5.10**	4.64	4.51	5.80	6.93
Total sales	**8.90**	9.17	8.91	9.06	9.66
Residential Average Annual Kilowatt-Hour Use Per Customer	**12,849**	12,028	12,864	12,582	12,969
Residential Average Annual Revenue Per Customer	**$ 1,555**	$ 1,489	$ 1,557	$ 1,529	$ 1,605
Plant Nameplate Capacity Ratings (year-end) (megawatts)	**15,308**	15,274	15,274	15,455	17,593
Maximum Peak-Hour Demand (megawatts):					
Winter	**15,372**	13,894	14,527	15,735	16,308
Summer	**15,748**	16,002	16,244	16,104	15,777
Annual Load Factor (percent)	**64.5**	61.1	61.9	61.9	61.2
Plant Availability (percent):					
Fossil-steam	**81.5**	85.0	87.4	85.6	86.3
Nuclear	**95.0**	93.5	95.6	94.1	90.8
Source of Energy Supply (percent):					
Gas	**29.1**	28.6	28.2	28.3	26.3
Coal	**21.1**	22.4	26.4	24.5	30.9
Nuclear	**17.6**	17.8	17.6	17.6	16.7
Hydro	**1.9**	1.0	1.1	1.6	1.3
Other	**0.3**	0.3	—	—	—
Purchased power —					
From non-affiliates	**7.3**	7.8	6.7	5.0	3.8
From affiliates	**22.7**	22.1	20.0	23.0	21.0
Total	**100.0**	100.0	100.0	100.0	100.0

SELECTED FINANCIAL AND OPERATING DATA 2014-2018
Mississippi Power Company 2018 Annual Report

	2018	2017	2016	2015	2014
Operating Revenues (in millions)	**$ 1,265**	$ 1,187	$ 1,163	$ 1,138	$ 1,243
Net Income (Loss) After Dividends on Preferred Stock (in millions)[a][b]	**$ 235**	$ (2,590)	$ (50)	$ (8)	$ (329)
Return on Average Common Equity (percent)[a][b]	**15.83**	(120.43)	(1.87)	(0.34)	(15.43)
Total Assets (in millions)[c]	**$ 4,886**	$ 4,866	$ 8,235	$ 7,840	$ 6,642
Gross Property Additions (in millions)	**$ 206**	$ 536	$ 946	$ 972	$ 1,389
Capitalization (in millions):					
Common stockholder's equity	**$ 1,609**	$ 1,358	$ 2,943	$ 2,359	$ 2,084
Redeemable preferred stock	**—**	33	33	33	33
Long-term debt[c]	**1,539**	1,097	2,424	1,886	1,621
Total (excluding amounts due within one year)	**$ 3,148**	$ 2,488	$ 5,400	$ 4,278	$ 3,738
Capitalization Ratios (percent):					
Common stockholder's equity	**51.1**	54.6	54.5	55.1	55.8
Redeemable preferred stock	**—**	1.3	0.6	0.8	0.9
Long-term debt[c]	**48.9**	44.1	44.9	44.1	43.3
Total (excluding amounts due within one year)	**100.0**	100.0	100.0	100.0	100.0
Customers (year-end):					
Residential	**153,423**	153,115	153,172	153,158	152,453
Commercial	**33,968**	33,992	33,783	33,663	33,496
Industrial	**445**	452	451	467	482
Other	**188**	173	175	175	175
Total	**188,024**	187,732	187,581	187,463	186,606
Employees (year-end)	**1,053**	1,242	1,484	1,478	1,478

(a) As a result of the Tax Reform Legislation, Mississippi Power recorded an income tax expense (benefit) of $(35) million and $372 million in 2018 and 2017, respectively.

(b) 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.

(c) A reclassification of debt issuance costs from Total Assets to Long-term debt of $9 million and a reclassification of deferred tax assets from Total Assets to Accumulated deferred income taxes of $105 million is reflected for 2014, in accordance with new accounting standards adopted in 2015 and applied retrospectively.

SELECTED FINANCIAL AND OPERATING DATA 2014-2018 (continued)
Mississippi Power Company 2018 Annual Report

	2018	2017	2016	2015	2014
Operating Revenues (in millions):					
Residential	**$ 273**	$ 257	$ 260	$ 238	$ 239
Commercial	**286**	285	279	256	257
Industrial	**321**	321	313	287	291
Other	**9**	(9)	7	(5)	8
Total retail	**889**	854	859	776	795
Wholesale — non-affiliates	**263**	259	261	270	323
Wholesale — affiliates	**91**	56	26	76	107
Total revenues from sales of electricity	**1,243**	1,169	1,146	1,122	1,225
Other revenues	**22**	18	17	16	18
Total	**$ 1,265**	$ 1,187	$ 1,163	$ 1,138	$ 1,243
Kilowatt-Hour Sales (in millions):					
Residential	**2,113**	1,944	2,051	2,025	2,126
Commercial	**2,797**	2,764	2,842	2,806	2,860
Industrial	**4,924**	4,841	4,906	4,958	4,943
Other	**37**	39	39	40	40
Total retail	**9,871**	9,588	9,838	9,829	9,969
Wholesale — non-affiliates	**3,980**	3,672	3,920	3,852	4,191
Wholesale — affiliates	**2,584**	2,024	1,108	2,807	2,900
Total	**16,435**	15,284	14,866	16,488	17,060
Average Revenue Per Kilowatt-Hour (cents):					
Residential	**12.92**	13.22	12.68	11.75	11.26
Commercial	**10.23**	10.31	9.82	9.12	8.99
Industrial	**6.52**	6.63	6.38	5.79	5.89
Total retail	**9.01**	8.91	8.73	7.90	7.97
Wholesale	**5.39**	5.53	5.71	5.20	6.06
Total sales	**7.56**	7.65	7.71	6.80	7.18
Residential Average Annual Kilowatt-Hour Use Per Customer	**13,768**	12,692	13,383	13,242	13,934
Residential Average Annual Revenue Per Customer	**$ 1,780**	$ 1,680	$ 1,697	$ 1,556	$ 1,568
Plant Nameplate Capacity Ratings (year-end) (megawatts)	**3,516**	3,628	3,481	3,561	3,867
Maximum Peak-Hour Demand (megawatts):					
Winter	**2,763**	2,390	2,195	2,548	2,618
Summer	**2,346**	2,322	2,384	2,403	2,345
Annual Load Factor (percent)	**55.8**	63.1	64.0	60.6	59.4
Plant Availability Fossil-Steam (percent)	**82.4**	89.1	91.4	90.6	87.6
Source of Energy Supply (percent):					
Gas	**86.1**	88.0	84.9	81.6	55.3
Coal	**6.9**	7.5	8.0	16.5	39.7
Purchased power —					
From non-affiliates	**4.7**	0.5	(0.3)	0.4	1.4
From affiliates	**2.3**	4.0	7.4	1.5	3.6
Total	**100.0**	100.0	100.0	100.0	100.0

SELECTED CONSOLIDATED FINANCIAL AND OPERATING DATA 2014-2018
Southern Power Company and Subsidiary Companies 2018 Annual Report

	2018	2017	2016	2015	2014
Operating Revenues (in millions):					
Wholesale — non-affiliates	**$ 1,757**	$ 1,671	$ 1,146	$ 964	$ 1,116
Wholesale — affiliates	**435**	392	419	417	383
Total revenues from sales of electricity	**2,192**	2,063	1,565	1,381	1,499
Other revenues	**13**	12	12	9	2
Total	**$ 2,205**	$ 2,075	$ 1,577	$ 1,390	$ 1,501
Net Income Attributable to Southern Power (in millions)[a]	**$ 187**	$ 1,071	$ 338	$ 215	$ 172
Cash Dividends on Common Stock (in millions)	**$ 312**	$ 317	$ 272	$ 131	$ 131
Return on Average Common Equity (percent)[a]	**4.62**	22.39	9.79	10.16	10.39
Total Assets (in millions)[b]	**$ 14,883**	$ 15,206	$ 15,169	$ 8,905	$ 5,233
Property, Plant, and Equipment — In Service (in millions)	**$ 13,271**	$ 13,755	$ 12,728	$ 7,275	$ 5,657
Capitalization (in millions):					
Common stockholders' equity	**$ 2,968**	$ 5,138	$ 4,430	$ 2,483	$ 1,752
Noncontrolling interests	**4,316**	1,360	1,245	781	219
Redeemable noncontrolling interests	**—**	—	164	43	39
Long-term debt[b]	**4,418**	5,071	5,068	2,719	1,085
Total (excluding amounts due within one year)	**$ 11,702**	$ 11,569	$ 10,907	$ 6,026	$ 3,095
Capitalization Ratios (percent):					
Common stockholders' equity	**25.4**	44.4	40.6	41.2	56.6
Noncontrolling interests	**36.9**	11.8	11.4	13.0	7.1
Redeemable noncontrolling interests	**—**	—	1.5	0.7	1.3
Long-term debt[b]	**37.7**	43.8	46.5	45.1	35.0
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	**37,164**	35,920	23,213	18,544	19,014
Wholesale — affiliates	**12,603**	12,811	15,950	16,567	11,194
Total	**49,767**	48,731	39,163	35,111	30,208
Plant Nameplate Capacity Ratings (year-end) (megawatts)	**11,888**	12,940	12,442	9,808	9,185
Maximum Peak-Hour Demand (megawatts):					
Winter	**2,867**	3,421	3,469	3,923	3,999
Summer	**4,210**	4,224	4,303	4,249	3,998
Annual Load Factor (percent)	**52.2**	49.1	50.0	49.0	51.8
Plant Availability (percent)	**99.9**	99.9	91.6	93.1	91.8
Source of Energy Supply (percent):					
Natural gas	**68.1**	67.7	79.4	89.5	86.0
Solar, Wind, and Biomass	**23.6**	22.8	12.1	4.3	2.9
Purchased power —					
From non-affiliates	**6.6**	7.8	6.8	4.7	6.4
From affiliates	**1.7**	1.7	1.7	1.5	4.7
Total	**100.0**	100.0	100.0	100.0	100.0
Employees (year-end)[c]	**491**	541	—	—	—

(a) As a result of the Tax Reform Legislation, Southern Power recorded an income tax expense (benefit) of $79 million and $(743) million in 2018 and 2017, respectively.

(b) A reclassification of debt issuance costs from Total Assets to Long-term debt of $11 million and a reclassification of deferred tax assets from Total Assets to Accumulated deferred income taxes of $306 million is reflected for 2014, in accordance with new accounting standards adopted in 2015 and applied retrospectively.

(c) Prior to December 2017, Southern Power had no employees but was billed for employee-related costs from SCS.

SELECTED CONSOLIDATED FINANCIAL AND OPERATING DATA 2014-2018
Southern Company Gas and Subsidiary Companies 2018 Annual Report

	Successor[a]			Predecessor[a]		
	2018[b]	2017	July 1, 2016 through December 31, 2016	January 1, 2016 through June 30, 2016	2015	2014
Operating Revenues (in millions)	**$ 3,909**	$ 3,920	$ 1,652	$ 1,905	$ 3,941	$ 5,385
Net Income Attributable to Southern Company Gas (in millions)[c]	**$ 372**	$ 243	$ 114	$ 131	$ 353	$ 482
Cash Dividends on Common Stock (in millions)	**$ 468**	$ 443	$ 126	$ 128	$ 244	$ 233
Return on Average Common Equity (percent)[c]	**4.23**	2.68	1.74	3.31	9.05	12.96
Total Assets (in millions)	**$ 21,448**	$ 22,987	$ 21,853	$ 14,488	$ 14,754	$ 14,888
Gross Property Additions (in millions)	**$ 1,399**	$ 1,525	$ 632	$ 548	$ 1,027	$ 769
Capitalization (in millions):						
Common stockholders' equity	**$ 8,570**	$ 9,022	$ 9,109	$ 3,933	$ 3,975	$ 3,828
Long-term debt	**5,583**	5,891	5,259	3,709	3,275	3,581
Total (excluding amounts due within one year)	**$ 14,153**	$ 14,913	$ 14,368	$ 7,642	$ 7,250	$ 7,409
Capitalization Ratios (percent):						
Common stockholders' equity	**60.6**	60.5	63.4	51.5	54.8	51.7
Long-term debt	**39.4**	39.5	36.6	48.5	45.2	48.3
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
Customers (period-end)						
Gas distribution operations	**4,247,804**	4,623,249	4,586,477	4,544,489	4,557,729	4,529,114
Gas marketing services	**697,384**	773,984	655,999	630,475	654,475	633,460
Total	**4,945,188**	5,397,233	5,242,476	5,174,964	5,212,204	5,162,574
Employees (period-end)	**4,389**	5,318	5,292	5,284	5,203	5,165

(a) As a result of the Merger, pushdown accounting was applied to create a new cost basis for Southern Company Gas' 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 are presented but are not comparable.

(b) During 2018, Southern Company Gas completed the Southern Company Gas Dispositions. See Note 15 to the financial statements under "Southern Company Gas" in Item 8 herein for additional information.

(c) As a result of the Tax Reform Legislation, Southern Company Gas recorded income tax expense (benefit) of $(3) million and $93 million in 2018 and 2017, respectively.

SELECTED CONSOLIDATED FINANCIAL AND OPERATING DATA 2014-2018 (continued)
Southern Company Gas and Subsidiary Companies 2018 Annual Report

	Successor[a]			Predecessor[a]		
	2018[b]	**2017**	**July 1, 2016 through December 31, 2016**	**January 1, 2016 through June 30, 2016**	**2015**	**2014**
Operating Revenues (in millions)						
Residential	**$ 1,886**	$ 2,100	$ 899	$ 1,101	$ 2,129	$ 2,877
Commercial	**546**	641	260	310	617	861
Transportation	**944**	811	269	290	526	458
Industrial	**140**	159	74	72	203	242
Other	**393**	209	150	132	466	947
Total	**$ 3,909**	$ 3,920	$ 1,652	$ 1,905	$ 3,941	$ 5,385
Heating Degree Days:						
Illinois	**6,101**	5,246	1,903	3,340	5,433	6,556
Georgia	**2,588**	1,970	727	1,448	2,204	2,882
Gas Sales Volumes (mmBtu in millions):						
Gas distribution operations						
Firm	**721**	667	274	396	695	766
Interruptible	**95**	95	47	49	99	106
Total	**816**	762	321	445	794	872
Gas marketing services						
Firm:						
Georgia	**37**	32	13	21	35	41
Illinois	**13**	12	4	8	13	17
Other	**20**	18	5	7	11	10
Interruptible large commercial and industrial	**14**	14	6	8	14	17
Total	**84**	76	28	44	73	85
Market share in Georgia (percent)	**29.0**	29.2	29.4	29.3	29.7	30.6
Wholesale gas services						
Daily physical sales (*mmBtu in millions/day*)	**6.7**	6.4	7.2	7.6	6.8	6.3

(a) As a result of the Merger, pushdown accounting was applied to create a new cost basis for Southern Company Gas' 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 are presented but are not comparable.

(b) During 2018, Southern Company Gas completed the Southern Company Gas Dispositions. See Note 15 to the financial statements under "Southern Company Gas" in Item 8 herein for additional information.

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

	Page
Southern Company	II-16
Alabama Power	II-70
Georgia Power	II-93
Mississippi Power	II-124
Southern Power	II-151
Southern Company Gas	II-171

OVERVIEW

Business Activities

Southern 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 traditional electric operating companies are vertically integrated utilities providing electric service in three Southeastern states as of January 1, 2019. On January 1, 2019, Southern Company completed its sale of Gulf Power to NextEra Energy for an aggregate cash purchase price of approximately $5.8 billion (less $1.3 billion of indebtedness assumed), subject to customary working capital adjustments. At December 31, 2018, the assets and liabilities of Gulf Power were classified as held for sale on Southern Company's balance sheet. Unless otherwise noted, the disclosures herein related to specific asset and liability balances at December 31, 2018 exclude assets and liabilities held for sale. See Note 15 under "Assets Held for Sale" for additional information. A preliminary gain of $2.5 billion pre-tax ($1.3 billion after tax) associated with the sale of Gulf Power is expected to be recorded in 2019.
- 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. On May 22, 2018, Southern Power sold a noncontrolling 33% equity interest in SP Solar, a limited partnership indirectly owning substantially all of Southern Power's solar facilities, for approximately $1.2 billion and, on December 11, 2018, Southern Power sold a noncontrolling tax equity interest in SP Wind, a holding company owning a portfolio of eight operating wind facilities, for approximately $1.2 billion. On November 5, 2018, Southern Power entered into an agreement to sell all of its equity interests in Plant Mankato (including the 385-MW expansion currently under construction) for an aggregate purchase price of approximately $650 million, which is expected to close mid-2019. The ultimate outcome of this matter cannot be determined at this time.
- Southern Company Gas distributes natural gas through its natural gas distribution utilities and is involved in several other complementary businesses including gas pipeline investments, wholesale gas services, and gas marketing services. In July 2018, Southern Company Gas completed sales of three of its natural gas distribution utilities.

See FUTURE EARNINGS POTENTIAL – "General" herein and Note 15 to the financial statements for additional information regarding disposition activities.

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, including CCR rules, reliability, fuel, restoration following major storms, and capital expenditures, including constructing new electric generating plants, expanding and improving 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 2 to the financial statements for additional information.

In 2018, Alabama Power, Georgia Power, Mississippi Power, Atlanta Gas Light, and Nicor Gas reached agreements with their respective state PSCs or other applicable state regulatory agencies relating to the regulatory impacts of the Tax Reform Legislation, which, for some companies, included capital structure adjustments expected to help mitigate the potential adverse impacts to certain of their credit metrics. See Note 2 to the financial statements for additional information regarding state PSC or other regulatory agency actions related to the Tax Reform Legislation. Also see MANAGEMENT'S DISCUSSION AND ANALYSIS – FUTURE EARNINGS POTENTIAL – "Income Tax Matters" and FINANCIAL CONDITION AND LIQUIDITY – "Credit Rating Risk" herein and Note 10 to the financial statements for information regarding the Tax Reform Legislation.

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, dispositions, and sales of partnership interests, 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. In general, Southern Power commits to the construction or acquisition of new generating capacity only after entering into or assuming long-term PPAs for the new facilities.

Southern Company's other business activities include providing energy solutions, including distributed energy infrastructure, energy efficiency products and services, and utility infrastructure services, to customers. 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 eight 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 Southern Company's financial performance.

Plant Vogtle Units 3 and 4 Status

In 2009, the Georgia PSC certified construction of Plant Vogtle Units 3 and 4 (with electric generating capacity of approximately 1,100 MWs each). Georgia Power holds a 45.7% ownership interest in Plant Vogtle Units 3 and 4. In March 2017, the EPC Contractor filed for bankruptcy protection under Chapter 11 of the U.S. Bankruptcy Code. In December 2017, the Georgia PSC approved Georgia Power's recommendation to continue construction. The current expected in-service dates remain November 2021 for Unit 3 and November 2022 for Unit 4.

In the second quarter 2018, Georgia Power revised its base capital cost forecast and estimated contingency to complete construction and start-up of Plant Vogtle Units 3 and 4 to $8.0 billion and $0.4 billion, respectively, for a total project capital cost forecast of $8.4 billion (net of $1.7 billion received under the Guarantee Settlement Agreement and approximately $188 million in related Customer Refunds), with respect to Georgia Power's ownership interest. Although Georgia Power believes these incremental costs are reasonable and necessary to complete the project and the Georgia PSC's order in the seventeenth VCM proceeding specifically states that the construction of Plant Vogtle Units 3 and 4 is not subject to a cost cap, Georgia Power did not seek rate recovery for the $0.7 billion increase in costs included in the current base capital cost forecast (or any related financing costs) in the nineteenth VCM report that was approved by the Georgia PSC on February 19, 2019. In connection with future VCM filings, Georgia Power may request the Georgia PSC to evaluate costs currently included in the construction contingency estimate for rate recovery as and when they are appropriately included in the base capital cost forecast. After considering the significant level of uncertainty that exists regarding the future recoverability of costs included in the construction contingency estimate since the ultimate outcome of these matters is subject to the outcome of future assessments by management, as well as Georgia PSC decisions in these future regulatory proceedings, Georgia Power recorded a total pre-tax charge to income of $1.1 billion ($0.8 billion after tax) in the second quarter 2018.

As a result of the increase in the total project capital cost forecast and Georgia Power's decision not to seek rate recovery of the increase in the base capital costs, the holders of at least 90% of the ownership interests in Plant Vogtle Units 3 and 4 were required to vote to continue construction. On September 26, 2018, the Vogtle Owners unanimously voted to continue construction of Plant Vogtle Units 3 and 4. In connection with the vote to continue construction, Georgia Power entered into (i) a binding term sheet (Vogtle Owner Term Sheet) with the other Vogtle Owners and certain of MEAG's wholly-owned subsidiaries, including MEAG Power SPVJ, LLC (MEAG SPVJ), to take certain actions which partially mitigate potential financial exposure for the other Vogtle Owners and (ii) a term sheet (MEAG Term Sheet) with MEAG and MEAG SPVJ to provide funding with respect to MEAG SPVJ's ownership interest in Plant Vogtle Units 3 and 4 under certain circumstances. On January 14, 2019, Georgia Power, MEAG, and MEAG SPVJ entered into an agreement to implement the provisions of the MEAG Term Sheet. On February 18, 2019, Georgia Power, the other Vogtle Owners, and certain of MEAG's wholly-owned subsidiaries entered into certain amendments to their joint ownership agreements to implement the provisions of the Vogtle Owner Term Sheet.

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

See FUTURE EARNINGS POTENTIAL – "Construction Program – Nuclear Construction" herein for additional information on Plant Vogtle Units 3 and 4.

Earnings

Consolidated net income attributable to Southern Company was $2.2 billion in 2018, an increase of $1.4 billion, or 164.4%, from the prior year. The increase was primarily due to charges of $3.4 billion ($2.4 billion after tax) in 2017 related to the Kemper IGCC at Mississippi Power, partially offset by a $1.1 billion ($0.8 billion after tax) charge in the second quarter 2018 for an

estimated probable loss on Georgia Power's construction of Plant Vogtle Units 3 and 4. The increase also reflects lower federal income tax expense as a result of the Tax Reform Legislation, partially offset by impairment charges, primarily associated with asset sales at Southern Power and Southern Company Gas.

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.

See Note 15 to the financial statements under "Southern Company Merger with Southern Company Gas" for additional information regarding the Merger.

Basic EPS was $2.18 in 2018, $0.84 in 2017, and $2.57 in 2016. Diluted EPS, which factors in additional shares related to stock-based compensation, was $2.17 in 2018, $0.84 in 2017, and $2.55 in 2016. EPS for 2018, 2017, and 2016 was negatively impacted by $0.04, $0.04, and $0.12 per share, respectively, as a result of increases 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 $2.38 in 2018, $2.30 in 2017, and $2.22 in 2016. In January 2019, Southern Company declared a quarterly dividend of 60 cents per share. This is the 285th consecutive quarter that Southern Company has paid a dividend equal to or higher than the previous quarter. For 2018, the dividend payout ratio was 109% compared to 273% for 2017. The decrease was due to an increase in earnings in 2018 resulting from charges related to the Kemper IGCC in 2017, partially offset by the charge related to construction of Plant Vogtle Units 3 and 4 in 2018. See "Earnings" and RESULTS OF OPERATIONS – "Electricity Business – Estimated Loss on Projects Under Construction" herein and Note 2 to the financial statements under "Georgia Power – Nuclear Construction" and "Mississippi Power – 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.

	2018	2017	2016
		(in millions)	
Electricity business	**$ 2,304**	$ 878	$ 2,571
Gas business	**372**	243	114
Other business activities	**(450)**	(279)	(237)
Net Income	**$ 2,226**	$ 842	$ 2,448

Electricity Business

Southern Company's electric utilities generate and sell electricity to retail and wholesale customers. The results of operations discussed below include the results of Gulf Power through December 31, 2018. See Note 15 to the financial statements under "Southern Company's Sale of Gulf Power" for additional information.

A condensed statement of income for the electricity business follows:

	Amount	Increase (Decrease) from Prior Year	
	2018	2018	2017
		(in millions)	
Electric operating revenues	$ 18,571	$ 31	$ 599
Fuel	4,637	237	39
Purchased power	971	108	113
Cost of other sales	66	(3)	11
Other operations and maintenance	4,635	45	(76)
Depreciation and amortization	2,565	108	224
Taxes other than income taxes	1,098	35	24
Estimated loss on plants under construction	1,097	(2,265)	2,934
Impairment charges	156	156	—
Gain on dispositions, net	—	40	(41)
Total electric operating expenses	15,225	(1,539)	3,228
Operating income	3,346	1,570	(2,629)
Allowance for equity funds used during construction	131	(21)	(48)
Interest expense, net of amounts capitalized	1,035	24	80
Other income (expense), net	144	17	58
Income taxes	207	125	(1,009)
Net income	2,379	1,417	(1,690)
Less:			
Dividends on preferred and preference stock of subsidiaries	16	(22)	(7)
Net income attributable to noncontrolling interests	59	13	10
Net Income Attributable to Southern Company	$ 2,304	$ 1,426	$ (1,693)

Electric Operating Revenues

Electric operating revenues for 2018 were $18.6 billion, reflecting a $31 million increase from 2017. Details of electric operating revenues were as follows:

	2018	2017
	(in millions)	
Retail electric — prior year	**$ 15,330**	$ 15,234
Estimated change resulting from —		
Rates and pricing	**(773)**	508
Sales growth (decline)	**84**	(71)
Weather	**300**	(281)
Fuel and other cost recovery	**281**	(60)
Retail electric — current year	**15,222**	15,330
Wholesale electric revenues	**2,516**	2,426
Other electric revenues	**664**	681
Other revenues	**169**	103
Electric operating revenues	**$ 18,571**	$ 18,540
Percent change	**0.2%**	3.3%

Retail electric revenues decreased $108 million, or 0.7%, in 2018 as compared to the prior year. The significant factors driving this change are shown in the preceding table. The decrease in rates and pricing in 2018 was primarily due to revenues deferred as regulatory liabilities for customer bill credits related to the Tax Reform Legislation and expected customer refunds at Alabama Power and Georgia Power.

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 2 to the financial statements under "Southern Company – Gulf Power," "Alabama Power – Rate RSE" and " – Rate CNP Compliance," "Georgia Power – Rate Plans," and " – Nuclear Construction" for additional information. Also see "Energy Sales" below for a discussion of changes in the volume of energy sold, including changes related to sales growth (decline) and weather.

Electric rates 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 and short-term opportunity sales. Wholesale electric revenues from PPAs (other than solar and wind PPAs) have both capacity and energy components. Capacity revenues generally represent the greatest contribution to net income and are designed to provide recovery of fixed costs plus a return on investment. Energy revenues will vary depending on fuel prices, the market prices of wholesale energy compared to the Southern Company system's generation, demand for energy within the Southern Company system's electric service territory, and the availability of the Southern Company system's generation. Increases and decreases in energy revenues that are driven by fuel prices are accompanied by an increase or decrease in fuel costs and do not have a significant impact on net income. Energy sales from solar and wind PPAs do not have a capacity charge and customers either purchase the energy output of a dedicated renewable facility through an energy charge or through a fixed price related to the energy. As a result, the 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 MRA 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:

	2018	2017	2016
		(in millions)	
Capacity and other	**$ 620**	$ 642	$ 570
Energy	**1,896**	1,784	1,356
Total	**$ 2,516**	$ 2,426	$ 1,926

In 2018, wholesale revenues increased $90 million, or 3.7%, as compared to the prior year due to a $112 million increase in energy revenues, partially offset by a $22 million decrease in capacity revenues. The increase in energy revenues was primarily related to Southern Power and includes new PPAs related to existing natural gas facilities, new renewable facilities, and an increase in the volume of KWHs sold at existing renewable facilities, partially offset by a decrease in non-PPA revenues from short-term sales. The decrease in capacity revenues was primarily due to the expiration of a wholesale contract in the fourth quarter 2017 at Georgia Power.

In 2017, wholesale revenues increased $500 million, or 26.0%, as compared to the prior year due to a $428 million increase in energy revenues and a $72 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.

Other Electric Revenues

Other electric revenues decreased $17 million, or 2.5%, in 2018 as compared to the prior year. The decrease is primarily related to a decrease in open access transmission tariff revenues, largely due to a lower rate related to the Tax Reform Legislation. Other electric revenues decreased $17 million, or 2.4%, in 2017, as compared to the prior year. The decrease reflects 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.

Energy Sales

Changes in revenues are influenced heavily by the change in the volume of energy sold from year to year. KWH sales for 2018 and the percent change from the prior year were as follows:

	Total KWHs	**Total KWH Percent Change**		**Weather-Adjusted Percent Change**	
	2018	**2018**	2017	**2018**	2017
	(in billions)				
Residential	**54.6**	**8.0%**	(5.3)%	**1.2%**	(0.3)%
Commercial	**53.5**	**2.1**	(2.6)	**0.5**	(0.9)
Industrial	**53.3**	**1.1**	—	**1.1**	—
Other	**0.8**	**(5.5)**	(4.0)	**(5.7)**	(3.9)
Total retail	**162.2**	**3.6**	(2.6)	**0.9%**	(0.4)%
Wholesale	**49.9**	**1.9**	32.4		
Total energy sales	**212.1**	**3.2%**	3.9 %		

Changes in retail energy sales are generally the result of changes in electricity usage by customers, changes in weather, and changes in the number of customers. Retail energy sales increased 5.7 billion KWHs in 2018 as compared to the prior year. This increase was primarily due to colder weather in the first quarter 2018 and warmer weather in the second and third quarters 2018 compared to the corresponding periods in 2017. Weather-adjusted residential KWH sales increased primarily due to customer growth. Weather-adjusted commercial KWH sales increased primarily due to customer growth, partially offset by decreased customer usage resulting from customer initiatives in energy savings and an ongoing migration to the electronic commerce business model. Industrial KWH energy sales increased primarily due to increased sales in the primary metals sector, partially offset by decreased sales in the paper sector.

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.

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 $66 million, or 64.1%, in 2018 as compared to the prior year. The increase was primarily due to unregulated sales of products and services that were reclassified from other income (expense), net as a result of the adoption of ASC 606, *Revenue from Contracts with Customers* (ASC 606). See Note 1 to the financial statements for additional information regarding the adoption of ASC 606.

Other revenues increased $20 million in 2017 as compared to the prior year. The increase was primarily due to additional third party infrastructure services.

Fuel and Purchased Power Expenses

The mix of fuel sources for the 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:

	2018	2017	2016
Total generation *(in billions of KWHs)*	**200**	194	188
Total purchased power *(in billions of KWHs)*	**21**	20	19
Sources of generation *(percent)* —			
Gas	**46**	46	46
Coal	**30**	30	33
Nuclear	**15**	16	16
Hydro	**3**	2	2
Other	**6**	6	3
Cost of fuel, generated *(in cents per net KWH)*[(a)] —			
Gas	**2.89**	2.79	2.48
Coal	**2.80**	2.81	3.04
Nuclear	**0.80**	0.79	0.81
Average cost of fuel, generated *(in cents per net KWH)*[(a)]	**2.50**	2.44	2.40
Average cost of purchased power *(in cents per net KWH)*[(b)]	**5.46**	5.19	4.81

(a) For 2018, cost of fuel, generated and average cost of fuel, generated excludes a $30 million adjustment associated with a May 2018 Alabama PSC accounting order related to excess deferred income taxes.

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

In 2018, total fuel and purchased power expenses were $5.6 billion, an increase of $345 million, or 6.6%, as compared to the prior year. The increase was primarily the result of a $178 million increase in the volume of KWHs generated and purchased primarily due to colder weather in the first quarter 2018 and warmer weather in the second and third quarters 2018 compared to the corresponding periods in 2017 and a $137 million increase in the average cost of fuel and purchased power primarily due to higher natural gas prices.

In addition, fuel expense increased $30 million in 2018 as a result of an Alabama PSC accounting order authorizing the amortization of a regulatory liability to offset under recovered fuel costs. See FUTURE EARNINGS POTENTIAL – "Regulatory Matters – Alabama Power – Tax Reform Accounting Order" herein for additional information.

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.

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 2018, fuel expense was $4.6 billion, an increase of $237 million, or 5.4%, as compared to the prior year. The increase was primarily due to a 3.6% increase in the average cost of natural gas per KWH generated, a 3.5% increase in the volume of KWHs generated by coal, and a 2.8% increase in the volume of KWHs generated by natural gas.

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.

Purchased Power

In 2018, purchased power expense was $971 million, an increase of $108 million, or 12.5%, as compared to the prior year. The increase was primarily due to a 5.2% increase in the average cost per KWH purchased, primarily as a result of higher natural gas prices, and a 5.2% increase in the volume of KWHs purchased.

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.

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.

Other Operations and Maintenance Expenses

Other operations and maintenance expenses increased $45 million, or 1.0%, in 2018 as compared to the prior year. The increase was primarily due to a $74 million increase in transmission and distribution costs, primarily related to additional vegetation management at Georgia Power, and $74 million in expenses from unregulated sales of products and services that were reclassified to other operations and maintenance expenses as a result of the adoption of ASC 606. In prior periods, these expenses were included in other income (expense), net. These increases were partially offset by a $32.5 million charge in the first quarter 2017 related to the write-down of Gulf Power's ownership of Plant Scherer Unit 3 in accordance with a rate case settlement agreement, a $30 million net decrease in employee compensation and benefits, including pension costs, largely due to a decrease in active medical costs at Alabama Power and a 2017 employee attrition plan at Georgia Power, and a $27 million decrease in customer accounts, service, and sales costs primarily due to cost-saving initiatives. See Note 1 to the financial statements for additional information regarding the adoption of ASC 606.

Other operations and maintenance expenses decreased $76 million, or 1.6%, 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, $46 million in transmission and distribution overhead line maintenance, $22 million in other employee compensation and benefits, and $22 million in customer accounts, service, and sales costs. Additionally, there was 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.

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 $108 million, or 4.4%, in 2018 as compared to the prior year. The increase was primarily related to additional plant in service. Additionally, the increase reflects $34 million in depreciation credits recognized in 2017, as authorized in Gulf Power's 2013 rate case settlement.

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 $34 million in depreciation credits recognized in accordance with Gulf Power's 2013 rate case settlement.

See Note 2 to the financial statements under "Southern Company – Regulatory Assets and Liabilities" and Note 5 to the financial statements under "Depreciation and Amortization" for additional information.

Taxes Other Than Income Taxes

Taxes other than income taxes increased $35 million, or 3.3%, in 2018 as compared to the prior year primarily due to increased property taxes associated with higher assessed values and an increase in municipal franchise fees primarily related to higher retail revenues at Georgia Power.

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.

Estimated Loss on Projects Under Construction

In the second quarter 2018, an estimated probable loss of $1.1 billion was recorded to reflect Georgia Power's revised estimate to complete construction and start-up of Plant Vogtle Units 3 and 4, which reflects the increase in costs included in the revised base capital cost forecast for which Georgia Power did not seek rate recovery and costs included in the revised construction contingency estimate for which Georgia Power may seek rate recovery as and when such costs are appropriately included in the base capital cost forecast. See Note 2 to the financial statements under "Georgia Power – Nuclear Construction" for additional information.

Charges associated with the Kemper IGCC of $37 million, $3.4 billion, and $428 million were recorded in 2018, 2017, and 2016, respectively. The 2018 pre-tax charge of $37 million primarily resulted from the abandonment and related closure activities and ongoing period costs, net of sales proceeds, for the mine and gasifier-related assets at the Kemper County energy facility. 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 grants awarded to the project by the DOE under the Clean Coal Power Initiative Round 2 and excluding the cost of the lignite mine and equipment, the cost of the CO_2 pipeline facilities, AFUDC, and certain general exceptions. See Note 2 to the financial statements under "Mississippi Power – Kemper County Energy Facility" for additional information.

Impairment Charges

In the second quarter 2018, Southern Power recorded a $119 million asset impairment charge in contemplation of the sale of Plant Oleander and Plant Stanton Unit A (together, the Florida Plants) and in the third quarter 2018 recorded a $36 million asset impairment charge on wind turbine equipment held for development projects. There were no asset impairment charges recorded in 2017 or 2016. See Note 15 to the financial statements under "Southern Power – Sales of Natural Gas Plants" and " – Development Projects" for additional information.

Gain on Dispositions, Net

Gain on dispositions, net decreased $40 million in 2018 and increased $41 million in 2017 as compared to the prior periods primarily due to gains on sales of assets at Georgia Power recorded in 2017.

Allowance for Equity Funds Used During Construction

AFUDC equity decreased $21 million, or 13.8%, in 2018 as compared to the prior year primarily due to Mississippi Power's suspension of the Kemper IGCC construction in June 2017, partially offset by a higher AFUDC rate resulting from a higher equity ratio and lower short-term borrowings at Georgia Power and a higher AFUDC base related to steam and transmission construction projects at Alabama Power.

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 in June 2017.

See Note 2 to the financial statements under "Mississippi Power – Kemper County Energy Facility" for additional information.

Interest Expense, Net of Amounts Capitalized

Interest expense, net of amounts capitalized increased $24 million, or 2.4%, in 2018 as compared to the prior year. The increase was primarily related to Mississippi Power and reflects a $33 million net reduction in interest recorded in 2017 following a settlement with the IRS related to research and experimental deductions and a $29 million reduction in interest capitalized related to the Kemper IGCC suspension in June 2017. The increase also reflects an increase in outstanding borrowings and higher interest rates at Alabama Power, partially offset by a decrease in outstanding borrowings at Georgia Power. See Note 10 to the financial statements under "Section 174 Research and Experimental Deduction" for additional information.

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 $33 million following Mississippi Power's settlement with the IRS related to research and experimental deductions. See Note 10 to the financial statements under "Unrecognized Tax Benefits" for additional information.

See Note 8 to the financial statements for additional information.

Other Income (Expense), Net

Other income (expense), net increased $17 million, or 13.4%, in 2018 as compared to the prior year primarily due to the settlement of Mississippi Power's Deepwater Horizon claim in May 2018 and a gain from a joint-development wind project at Southern Power, which is attributable to Southern Power's partner in the project and fully offset within noncontrolling interests, partially offset by an increase in charitable donations. See Note 3 to the financial statements under "General Litigation Matters – Mississippi Power" and Note 7 to the financial statements under "Southern Power" for additional information.

Other income (expense), net increased $58 million, or 84.1%, in 2017 as compared to the prior year primarily due to a decrease in non-service cost components of net periodic pension and other postretirement benefits costs, partially offset by 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. See Note 1 under "Recently Adopted Accounting Standards" and Note 11 to the financial statements for additional information on net periodic pension and other postretirement benefit costs.

Income Taxes

Income taxes increased $125 million, or 152.4%, in 2018 as compared to the prior year. The increase was primarily due to an increase in pre-tax earnings, primarily resulting from charges recorded in 2017 related to the Kemper IGCC at Mississippi Power, partially offset by the estimated probable loss on Plant Vogtle Units 3 and 4 at Georgia Power recognized in the second quarter 2018. This increase was partially offset by lower federal income tax expense, as well as benefits from the flowback of excess deferred income taxes as a result of the Tax Reform Legislation.

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.

See Note 10 to the financial statements for additional information.

Dividends on Preferred and Preference Stock of Subsidiaries

Dividends on preferred and preference stock of subsidiaries decreased $22 million, or 57.9%, in 2018 as compared to 2017 and decreased $7 million, or 15.6%, in 2017 as compared to 2016. These decreases were primarily due to the 2017 redemptions of all outstanding shares of preferred and preference stock at Georgia Power and Gulf Power. See Note 8 to the financial statements for additional information.

Net Income Attributable to Noncontrolling Interests

Substantially all noncontrolling interests relate to renewable projects at Southern Power. Net income attributable to noncontrolling interests increased $13 million, or 28.3%, in 2018, as compared to the prior year. The increase was primarily due to $20 million of net income allocations due to the sale of a noncontrolling 33% equity interest in SP Solar in 2018 and $14

million of other income allocations attributable to a joint-development wind project, partially offset by a reduction of $19 million due to HLBV income allocations between Southern Power and tax equity partners for partnerships entered into during 2018. In 2017, noncontrolling interests increased $10 million, or 28%, compared to 2016 primarily due to additional net income allocations from new solar partnerships.

See Note 15 under "Southern Power" for additional information.

Gas Business

Southern Company Gas distributes natural gas through utilities in four states and is involved in several other complementary businesses including gas pipeline investments, wholesale gas services, and gas marketing services.

A condensed statement of income for the gas business follows:

	Amount	Increase (Decrease) from Prior Year	
	2018	2018	2017
		(in millions)	
Operating revenues	$ 3,909	$ (11)	$ 2,268
Cost of natural gas	1,539	(62)	988
Cost of other sales	12	(17)	19
Other operations and maintenance	981	36	424
Depreciation and amortization	500	(1)	263
Taxes other than income taxes	211	27	113
Impairment charges	42	42	—
Gain on dispositions, net	(291)	(291)	—
Total operating expenses	2,994	(266)	1,807
Operating income	915	255	461
Earnings from equity method investments	148	42	46
Interest expense, net of amounts capitalized	228	28	119
Other income (expense), net	1	(43)	32
Income taxes	464	97	291
Net income	$ 372	$ 129	$ 129

In the table above, the 2018 changes for Southern Company Gas reflect the year ended December 31, 2018 compared to 2017. The Southern Company Gas Dispositions were completed by July 29, 2018 and represent the primary variance driver for the 2018 changes. Additional detailed variance explanations are provided herein. The 2017 changes reflect the 12-month period in 2017 compared to the six-month period following the Merger closing on July 1, 2016, which is the primary variance driver. Additionally, earnings from equity method investments include Southern Company Gas' acquisition of a 50% equity interest in SNG completed in September 2016. See Note 15 to the financial statements under "Southern Company Gas" for additional information on Southern Company Gas' investment in SNG and the Southern Company Gas Dispositions.

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 2018, the percentage of operating revenues and net income generated during the Heating Season (January through March and November through December) were 68.7% and 96.0%, respectively. For 2017, the percentage of operating revenues and net income generated during the Heating Season were 67.3% and 73.7%, 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.

Operating Revenues

Operating revenues in 2018 were $3.9 billion, reflecting an $11 million decrease from 2017. Details of operating revenues were as follows:

		(in millions)	*(% change)*
Operating revenues – prior year	$	3,920	
Estimated change resulting from –			
Infrastructure replacement programs and base rate changes		31	0.8
Gas costs and other cost recovery		3	0.1
Weather		13	0.3
Wholesale gas services		138	3.5
Southern Company Gas Dispositions(*)		(228)	(5.8)
Other		32	0.8
Operating revenues – current year	$	3,909	(0.3)%

(*) Includes a $154 million decrease related to natural gas revenues, including alternative revenue programs, and a $74 million decrease related to other revenues. See Note 15 to the financial statements under "Southern Company Gas" for additional information.

Revenues from infrastructure replacement programs and base rate changes increased in 2018 primarily due to a $48 million increase at Nicor Gas, partially offset by a $12 million decrease at Atlanta Gas Light. These amounts include the natural gas distribution utilities' continued investments recovered through infrastructure replacement programs and base rate increases less revenue reductions for the impacts of the Tax Reform Legislation. See Note 2 to the financial statements under "Southern Company Gas" for additional information.

Revenues increased due to colder weather, as determined by Heating Degree Days, in 2018 compared to 2017.

Revenues from wholesale gas services increased in 2018 primarily due to increased commercial activity, partially offset by derivative losses.

Other revenues increased in 2018 primarily due to a $15 million increase from the Dalton Pipeline being placed in service in August 2017 and a $14 million increase in Nicor Gas' revenue taxes.

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 the natural gas distribution utilities.

Cost of Natural Gas

Excluding Atlanta Gas Light, which does not sell natural gas to end-use customers, the natural gas distribution utilities charge their 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 natural gas distribution utilities defer or accrue 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 the natural gas distribution utilities. Cost of natural gas at the natural gas distribution utilities represented 83.2% of the total cost of natural gas for 2018.

Gas marketing services customers are charged for actual and estimated natural gas consumed. Cost of natural gas includes the cost of fuel and associated transportation costs, lost and unaccounted for gas, adjustments to reduce the value of inventories to market value, if applicable, and gains and losses associated with certain derivatives.

Cost of natural gas in 2018 was $1.5 billion, a decrease of $62 million, or 3.9%, compared to 2017, which was substantially all as a result of the Southern Company Gas Dispositions.

Cost of Other Sales

Cost of other sales in 2018 was $12 million, a decrease of $17 million, or 58.6%, compared to 2017 primarily related to the disposition of Pivotal Home Solutions.

Other Operations and Maintenance Expenses

Other operations and maintenance expenses increased $36 million, or 3.8%, in 2018 compared to the prior year. Excluding a $39 million decrease related to the Southern Company Gas Dispositions, other operations and maintenance expenses increased $75 million. This increase was primarily due to a $53 million increase in compensation and benefit costs, including a $12 million one-time increase for the adoption of a new paid time off policy to align with the Southern Company system, a $28 million increase in disposition-related costs, and an $11 million expense for a litigation settlement to facilitate the sale of Pivotal Home Solutions. These increases were partially offset by a $27 million decrease in bad debt expense primarily at Nicor Gas, which was offset by a decrease in revenues as a result of the related regulatory recovery mechanism. See Note 3 to the financial statements under "General Litigation Matters – Southern Company Gas" for additional information on the litigation settlement.

Depreciation and Amortization

Depreciation and amortization decreased $1 million, or 0.2%, in 2018 compared to the prior year. Excluding a $37 million decrease related to the Southern Company Gas Dispositions, depreciation and amortization increased $36 million. The increase was primarily due to continued infrastructure investments at the natural gas distribution utilities, partially offset by lower amortization of intangible assets as a result of fair value adjustments in acquisition accounting at gas marketing services. See Note 2 to the financial statements under "Southern Company Gas" for additional information on infrastructure replacement programs.

Taxes Other Than Income Taxes

Taxes other than income taxes increased $27 million, or 14.7%, in 2018 compared to the prior year. Excluding a $4 million decrease related to the Southern Company Gas Dispositions, taxes other than income taxes increased $31 million. This increase primarily reflects a $13 million increase in revenue tax expenses as a result of higher natural gas revenues, a $12 million increase in Nicor Gas' invested capital tax that reflects a $7 million credit in 2017 to establish a related regulatory asset, and a $4 million increase in property taxes. See Note 15 to the financial statements under "Southern Company Gas" for additional information on the Southern Company Gas Dispositions.

Impairment Charges

A goodwill impairment charge of $42 million was recorded in 2018 in contemplation of the sale of Pivotal Home Solutions. See Notes 1 and 15 to the financial statements under "Goodwill and Other Intangible Assets and Liabilities" and "Southern Company Gas – Sale of Pivotal Home Solutions," respectively, for additional information.

Gain on Dispositions, Net

Gain on dispositions, net was $291 million in 2018 and was associated with the Southern Company Gas Dispositions. The income tax expense on these gains included income tax expense on goodwill not deductible for tax purposes and for which a deferred tax liability had not been recorded previously.

Earnings from Equity Method Investments

Earnings from equity method investments increased $42 million, or 39.6%, in 2018 compared to the prior year. The increase was primarily due to higher earnings from Southern Company Gas' equity method investment in SNG from new rates effective September 2018 and lower operations and maintenance expenses due to the timing of pipeline maintenance. See Note 7 to the financial statements under "Southern Company Gas – Equity Method Investments" for additional information.

Interest Expense, Net of Amounts Capitalized

Interest expense, net of amounts capitalized increased $28 million, or 14.0%, in 2018 compared to the prior year. The increase was primarily due to $21 million of additional interest expense related to new debt issuances and a $4 million reduction in capitalized interest primarily due to the Dalton Pipeline being placed in service in August 2017.

Other Income (Expense), Net

Other income (expense), net decreased $43 million, or 97.7%, in 2018 compared to the prior year. Excluding a $3 million decrease related to the Southern Company Gas Dispositions, other income (expense), net decreased $40 million. This decrease

was primarily due to a $23 million increase in charitable donations and a $13 million decrease in gains from the settlement of contractor litigation claims. See Note 2 to the financial statements under "Southern Company Gas – Infrastructure Replacement Programs and Capital Projects – PRP" for additional information on the contractor litigation settlement.

Income Taxes

Income taxes increased $97 million, or 26.4%, in 2018 compared to the prior year. Excluding a $329 million increase related to the Southern Company Gas Dispositions, including tax expense on the goodwill for which a deferred tax liability had not been previously provided, income taxes decreased $232 million. This decrease was primarily due to a lower federal income tax rate and the flowback of excess deferred taxes as a result of the Tax Reform Legislation. In addition, 2017 included additional tax expense of $130 million from the revaluation of deferred tax assets associated with the Tax Reform Legislation, the enactment of the State of Illinois income tax legislation, and new income tax apportionment factors in several states. See Note 10 to the financial statements for additional information.

Other Business Activities

Southern Company's other business activities primarily include the parent company (which does not allocate operating expenses to business units); PowerSecure, which was acquired on May 9, 2016 and is a provider of energy solutions, including distributed infrastructure, energy efficiency products and services, and utility infrastructure services, to customers; Southern Company Holdings, Inc. (Southern Holdings), which invests in various projects, including leveraged lease projects; and Southern Linc, which 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.

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

	Amount	Increase (Decrease) from Prior Year	
	2018	2018	2017
		(in millions)	
Operating revenues	**$ 1,015**	**$ 444**	$ 268
Cost of other sales	**728**	**313**	223
Other operations and maintenance	**273**	**69**	9
Depreciation and amortization	**66**	**14**	21
Taxes other than income taxes	**6**	**3**	—
Impairment charges	**12**	**12**	—
Total operating expenses	**1,085**	**411**	253
Operating income (loss)	**(70)**	**33**	15
Interest expense	**579**	**96**	178
Other income (expense), net	**(23)**	**(23)**	30
Income taxes (benefit)	**(222)**	**85**	(91)
Net income (loss)	**$ (450)**	**$ (171)**	$ (42)

In the table above, the 2018 changes for these other business activities reflect the inclusion of PowerSecure for the year ended December 31, 2018 compared to 2017. The 2017 changes reflect the inclusion of PowerSecure for the 12-month period in 2017 compared to the eight-month period following the acquisition on May 9, 2016, which is the primary variance driver. Additional detailed variance explanations are provided herein. See Note 15 to the financial statements under "Southern Company Acquisition of PowerSecure" for additional information.

Operating Revenues

Southern Company's operating revenues for these other business activities increased $444 million, or 77.8%, in 2018 as compared to the prior year. The increase was primarily related to PowerSecure's storm restoration services in Puerto Rico.

Cost of Other Sales

Cost of other sales for these other business activities increased $313 million, or 75.4% in 2018. The increase was primarily related to PowerSecure's storm restoration services in Puerto Rico.

Other Operations and Maintenance Expenses

Other operations and maintenance expenses for these other business activities increased $69 million, or 33.8%, in 2018 as compared to the prior year. The increase was primarily due to PowerSecure's storm restoration services in Puerto Rico and parent company expenses related to the sale of Gulf Power. Other operations and maintenance expenses for these other business activities increased $9 million, or 4.6%, 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.

Impairment Charges

Impairment charges for these other business activities were $12 million in 2018. These charges were associated with Southern Linc's tower leases and were recorded in contemplation of the sale of Gulf Power.

Interest Expense

Interest expense for these other business activities increased $96 million, or 19.9%, in 2018 as compared to the prior year primarily due to an increase in variable interest rates and average outstanding debt at the parent company. 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. See Note 8 to the financial statements for additional information.

Other Income (Expense), Net

Other income (expense), net for these other business activities decreased $23 million in 2018 as compared to the prior year primarily due to charitable donations, partially offset by leveraged lease income at Southern Holdings. See Note 1 to the financial statements for additional information. Other income (expense), net for these other business activities increased $30 million in 2017 as compared to the prior year primarily due to expenses associated with bridge financing for the Merger in 2016.

Income Taxes (Benefit)

The income tax benefit for these other business activities decreased $85 million, or 27.7%, in 2018 as compared to the prior year primarily as a result of the Tax Reform Legislation, partially offset by an increase in pre-tax losses at the parent company. 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. See FUTURE EARNINGS POTENTIAL – "Income Tax Matters – Federal Tax Reform Legislation" herein and Note 10 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 traditional electric operating companies operate as vertically integrated utilities providing electric service to customers within their service territories in the Southeast. On January 1, 2019, Southern Company completed the sale of Gulf Power, one of the traditional electric operating companies, to NextEra Energy. The natural gas distribution utilities provide service to customers in their service territories in Illinois, Georgia, Virginia, and Tennessee. In July 2018, Southern Company Gas completed sales of three of its natural gas distribution utilities. 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. Retail rates and earnings are reviewed and may be adjusted periodically within certain limitations. Prices for wholesale electricity sales and natural gas distribution, interconnecting transmission lines, and the exchange of electric power are regulated by the FERC. Southern Power continues to focus on long-term PPAs. In 2018, Southern Power completed sales of noncontrolling interests in entities indirectly owning substantially all of its solar facilities and eight of its wind facilities and also completed sales and entered into an agreement to sell certain of its natural gas plants. See ACCOUNTING POLICIES – "Application of Critical Accounting Policies

and Estimates – Utility Regulation" herein and Note 2 to the financial statements for additional information about regulatory matters.

The results of operations for the past three years are not necessarily indicative of Southern Company's future earnings potential. Future earnings will be impacted by the 2018 disposition activities described herein and in Note 15 to the financial statements. 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 constructive regulatory environments that allow for the timely recovery of prudently-incurred costs during a time of increasing costs, continued customer growth, and, for the traditional electric operating companies, the weak pace of growth in electricity use per customer, especially in residential and commercial markets. Plant Vogtle Units 3 and 4 construction and rate recovery and the profitability of Southern Power's competitive wholesale business are also major factors.

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 more 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, the development or acquisition of renewable facilities and other 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.

On January 1, 2019, Southern Company completed the sale of Gulf Power to NextEra Energy for an aggregate cash purchase price of approximately $5.8 billion (less $1.3 billion of indebtedness assumed), subject to customary working capital adjustments. In 2018, net income attributable to Gulf Power was $160 million.

On June 4, 2018, Southern Company Gas completed the stock sale of Pivotal Home Solutions to American Water Enterprises LLC for a total cash purchase price of $365 million. On July 1, 2018, a Southern Company Gas subsidiary, Pivotal Utility Holdings, completed the sales 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. On July 29, 2018, Southern Company Gas and its wholly-owned direct subsidiary, NUI Corporation, completed the stock sale of Pivotal Utility Holdings, which primarily consisted of Florida City Gas, to NextEra Energy for a total cash purchase price of $587 million. The total cash purchase price for each transaction includes final working capital and other adjustments.

The Southern Company Gas Dispositions resulted in a net loss of $51 million, which includes $342 million of tax expense. The after-tax impacts of these dispositions included income tax expense on goodwill not deductible for tax purposes and for which a deferred tax liability had not been recorded previously. In addition, a goodwill impairment charge of $42 million was recorded during 2018 in contemplation of the sale of Pivotal Home Solutions.

On May 22, 2018, Southern Power sold a noncontrolling 33% equity interest in SP Solar, a limited partnership indirectly owning substantially all of Southern Power's solar facilities, for approximately $1.2 billion and, on December 11, 2018, sold a noncontrolling tax equity interest in SP Wind, a holding company owning a portfolio of eight operating wind facilities, for approximately $1.2 billion. Additionally, on November 5, 2018, Southern Power entered into an agreement to sell all of its equity interests in Plant Mankato (including the 385-MW expansion currently under construction) for an aggregate purchase price of approximately $650 million. The completion of the disposition is subject to the expansion unit reaching commercial operation as well as various other customary conditions to closing, including FERC and state commission approvals, and the sale is expected

to close mid-2019. The ultimate outcome of this matter cannot be determined at this time. On December 4, 2018, Southern Power sold of all of its equity interests in the Florida Plants to NextEra Energy for approximately $203 million.

See Note 15 to the financial statements for additional information regarding disposition activities.

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 comprehensive environmental compliance and GHG strategies to assess upcoming requirements and compliance costs associated with these environmental laws and regulations. The costs, including capital expenditures, operations and maintenance costs, and costs reflected in ARO liabilities, required to comply with environmental laws and regulations and to achieve stated goals may impact future electric generating unit retirement and replacement decisions, results of operations, cash flows, and/or financial condition. Related costs may result from the installation of additional environmental controls, closure and monitoring of CCR facilities, unit retirements, or changing fuel sources for certain existing units, as well as related upgrades to the Southern Company system's transmission and distribution (electric and natural gas) systems. A major portion of these costs is expected to be recovered through retail and wholesale rates. The ultimate impact of environmental laws and regulations and the GHG goals discussed herein will depend on various factors, such as state adoption and implementation of requirements, the availability and cost of any deployed technology, fuel prices, 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 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/or 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 $140 million of funding that has restored or enhanced more than 2 million acres of habitat since 2003; the removal of more than 15.5 million pounds of trash and debris from waterways between 2000 and 2018 through the Renew Our Rivers program; a 21.2% reduction in surface water withdrawal from 2015 to 2017; reductions in SO_2 and NO_X air emissions of 98% and 89%, respectively, from 1990 to 2017; the reduction of mercury air emissions of over 95% from 2005 to 2017; and the Southern Company system's changing energy mix.

Through 2018, the traditional electric operating companies have invested approximately $14.2 billion in environmental capital retrofit projects to comply with environmental requirements, with annual totals of approximately $1.3 billion, $0.9 billion, and $0.5 billion for 2018, 2017, and 2016, 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 $1.4 billion from 2019 through 2023, with annual totals of approximately $0.5 billion, $0.2 billion, $0.3 billion, $0.3 billion, and $0.2 billion for 2019, 2020, 2021, 2022, and 2023, respectively. These estimates do not include any potential compliance costs associated with pending 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 substantial expenditures associated with ash pond closure and ground water monitoring under the CCR Rule, which are reflected in Southern Company's ARO liabilities. See FINANCIAL CONDITION AND LIQUIDITY – "Capital Requirements and Contractual Obligations" herein and Note 6 to the financial statements 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) to protect and improve the nation's air quality, which it reviews and revises periodically. Following a NAAQS revision, states are required to develop an EPA-approved plan to protect air quality. These state plans 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 electric generating facilities. All areas within the Southern Company system's electric service territory have been designated as attainment for all NAAQS

except for a seven-county area within metropolitan Atlanta that is not in attainment with the 2015 ozone NAAQS and the area surrounding Plant Hammond, in Georgia, which will not be designated attainment or nonattainment for the 2010 SO_2 standard until December 2020. If areas are designated as nonattainment in the future, increased compliance costs could result. See "Regulatory Matters – Georgia Power – Integrated Resource Plan" herein for information regarding Georgia Power's request to decertify and retire Plant Hammond.

In 2011, the EPA finalized the Cross-State Air Pollution Rule (CSAPR) to address impacts of SO_2 and NO_X emissions from fossil fuel-fired electric generating plants. CSAPR establishes emissions trading programs and budgets for certain states and allocates emissions allowances for sources in those states. In 2016, the EPA published a final rule establishing more stringent ozone season NO_X emissions budgets in Alabama, Mississippi, and Texas. Georgia's ozone season NO_X emissions budget remained unchanged. The EPA also removed North Carolina from this particular CSAPR program. The outcome of ongoing CSAPR litigation concerning the 2016 CSAPR rule, to which Mississippi Power is a party, could have an impact on the State of Mississippi's ozone season NO_X emissions budget. Increases in either future fossil fuel-fired generation or the availability or 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 demonstrating continued reasonable progress towards achieving visibility improvement goals. These plans could require reductions in certain pollutants, such as particulate matter, SO_2, and NO_X, which could result in increased compliance costs. The EPA approved the regional progress SIPs for the States of Alabama and Georgia, but only issued a limited approval of the regional progress SIP for the State of Mississippi because Mississippi must revise the best available retrofit technology (BART) provisions of its SIP. Therefore, Mississippi Power's Plant Daniel is the only electric generating unit in the Southern Company system that continues to be evaluated under the regional haze BART provisions. Mississippi Power is required to submit Plant Daniel's BART analysis to the State of Mississippi by summer 2019. Requirements for further reduction of these pollutants at Plant Daniel could increase compliance costs.

Water Quality

In 2014, the EPA finalized requirements under Section 316(b) of the Clean Water Act (CWA) to regulate cooling water intake structures (CWIS) to minimize their effects on fish and other aquatic life at existing power plants (e.g. coal, natural gas, oil, and nuclear generating plants) and manufacturing facilities. The regulation requires plant-specific studies to determine applicable CWIS changes to protect organisms that either get caught on the intake screens (impingement) or are drawn into the cooling system (entrainment). The Southern Company system is conducting these studies and currently anticipates applicable CWIS changes may include fish-friendly CWIS screens with fish return systems and minor additions of monitoring equipment at certain plants. However, the ultimate impact of this rule will depend on the outcome of these plant-specific studies, any additional protective measures required to be incorporated into each plant's National Pollutant Discharge Elimination System (NPDES) permit based on site-specific factors, and the outcome of any legal challenges.

In 2015, the EPA finalized the steam electric effluent limitations guidelines (ELG) rule (2015 ELG Rule) that set national standards for wastewater discharges from new and existing steam electric generating units generating greater than 50 MWs. The 2015 ELG Rule prohibits effluent discharges of certain waste streams and imposes stringent limits on flue gas desulfurization (scrubber) wastewater discharges. The revised technology-based limits and the CCR Rule require extensive changes to existing ash and wastewater management systems or the installation and operation of new ash and wastewater management systems. Compliance with the 2015 ELG Rule is expected to require capital expenditures and increased operational costs primarily for the traditional electric operating companies' coal-fired electric generation. State environmental agencies will incorporate specific compliance applicability dates in the NPDES permitting process for each ELG waste stream no later than December 31, 2023. The EPA is scheduled to issue a new rulemaking by December 2019 that could revise the limitations and applicability dates of two of the waste streams regulated in the 2015 ELG Rule. The impact of any changes to the 2015 ELG Rule will depend on the content of the new rule and the outcome of any legal challenges.

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, canals, and wastewater treatment ponds), which could impact new generation projects and permitting and reporting requirements associated with the installation, expansion, and maintenance of transmission, distribution, and pipeline projects. The EPA and the Corps are expected to publish a final rule in 2019 to replace the 2015 WOTUS definition. The impact of any changes to the 2015 WOTUS rule will depend on the content of this final rule and the outcome of any legal challenges.

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 (ash ponds) at active generating power plants. In addition to the EPA's CCR Rule, the States of Alabama and Georgia have also finalized regulations regarding the handling of CCR within their respective states. The EPA's CCR Rule requires landfills and ash ponds to be evaluated against a set of performance criteria and potentially closed if minimum criteria are not met. Closure of existing landfills and ash ponds could require installation of equipment and infrastructure to manage CCR in accordance with the CCR Rule. Based on cost estimates for closure and monitoring of landfills and ash ponds pursuant to the CCR Rule, the Southern Company system recorded AROs for each CCR unit in 2015. As further analysis was performed and closure details were developed, the traditional electric operating companies have continued to periodically update these cost estimates, as discussed further below.

The EPA published certain amendments to the CCR Rule, which became effective August 29, 2018. These amendments extend the date from April 2019 to October 31, 2020 to cease sending CCR and other waste streams to ash ponds that demonstrate compliance with all except two of the specified performance criteria.

On August 21, 2018, the U.S. Court of Appeals for the District of Columbia Circuit issued a decision suggesting the EPA should regulate previously-excluded inactive ash ponds located at retired generation facilities and questioning both the ability of unlined ash ponds to continue operating no matter the performance criteria results and the classification of clay-lined landfills and ash ponds. These developments could impact the expected timing of the traditional electric operating companies' landfill and ash pond closure activities, but the extent of any impact will depend on the outcome of ongoing litigation, anticipated EPA rulemaking action to establish further guidance, and the outcome of any legal challenges.

In June 2018, Alabama Power recorded an increase of approximately $1.2 billion to its AROs related to the CCR Rule. The revised cost estimates were based on information from feasibility studies performed on ash ponds in use at plants operated by Alabama Power, including at a plant jointly-owned by Mississippi Power. During the second quarter 2018, Alabama Power's management completed its analysis of these studies which indicated that additional closure costs, primarily related to increases in estimated ash volume, water management requirements, and design revisions, will be required to close these ash ponds under the planned closure-in-place methodology. As the level of work becomes more defined in the next 12 months, it is likely that these cost estimates will change and the change could be material.

In December 2018, Georgia Power recorded an increase of approximately $3.1 billion to its AROs related to the CCR Rule and the related state rule. During the second half of 2018, Georgia Power completed a strategic assessment related to its plans to close the ash ponds at all of its generating plants in compliance with the CCR Rule and the related state rule. This assessment included engineering and constructability studies related to design assumptions for ash pond closures and advanced engineering methods. The results indicated that additional closure costs will be required to close these ash ponds, primarily due to changes in closure strategies, the estimated amount of ash to be excavated, and additional water management requirements necessary to support closure strategies. These factors also impact the estimated timing of future cash outlays.

The traditional electric operating companies expect to periodically update their ARO cost estimates. Absent continued recovery of ARO costs through regulated rates, Southern Company's results of operations, cash flows, and financial condition could be materially impacted. See FINANCIAL CONDITION AND LIQUIDITY – "Capital Requirements and Contractual Obligations" herein and Note 6 to the financial statements for additional information.

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

Nuclear Decommissioning

In June 2018, Alabama Power completed an updated decommissioning cost site study for Plant Farley. The estimated cost of decommissioning based on the study resulted in an increase in Alabama Power's ARO liability of approximately $300 million. Amounts previously contributed to Alabama Power's external trust funds are currently projected to be adequate to meet the updated decommissioning obligations.

In December 2018, Georgia Power completed updated decommissioning cost site studies for Plant Hatch and Plant Vogtle Units 1 and 2. The estimated cost of decommissioning based on the studies resulted in an increase in Georgia Power's ARO liability of approximately $130 million. Georgia Power currently collects $4 million and $2 million annually in rates, which is used to fund external nuclear decommissioning trusts for Plant Hatch and Plant Vogtle Units 1 and 2, respectively. Georgia Power expects the Georgia PSC to review and adjust, if necessary, these amounts in the Georgia Power 2019 Base Rate Case.

See Note 6 to the financial statements for additional information.

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 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 and Georgia 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 Remediation" for additional information.

Global Climate Issues

On August 31, 2018, the EPA published a proposed rule known as the Affordable Clean Energy (ACE) Rule, which is intended to replace a regulation enacted in 2015 known as the Clean Power Plan (CPP), that would limit CO_2 emissions from existing fossil fuel-fired electric generating units. The CPP has been stayed by the U.S. Supreme Court since 2016. The ACE Rule would require states to develop GHG unit-specific emission rate standards based on heat-rate efficiency improvements for existing fossil fuel-fired steam units. As proposed, combustion turbines, including natural gas combined cycles, are not affected sources. As of January 1, 2019, the Southern Company system has ownership interests in 40 fossil fuel-fired steam units to which the proposed ACE Rule is applicable. The ultimate impact of this rule to the Southern Company system is currently unknown and will depend on changes between the proposal and the final rule, subsequent state plan developments and requirements, and any associated legal challenges.

On December 20, 2018, the EPA published a proposed review of the Standards of Performance for Greenhouse Gas Emissions from New, Modified, and Reconstructed Stationary Sources: Electric Utility Generating Units final rule (2015 NSPS rule). The EPA's final 2015 NSPS rule set standards of performance for new, modified, and reconstructed electric utility generating units which included stationary combustion turbines and fossil-fired steam boilers. This proposal reduces the stringency of the 2015 NSPS rule by not basing the new and reconstructed fossil-fired steam boiler and IGCC standards on partial carbon capture and sequestration. The impact of any changes to this rule will depend on the content of the final rule and the outcome of any legal challenges.

Additional 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 70% coal and 15% natural gas in 2007 to a mix of 30% coal and 46% natural gas in 2018, along with over 8,000 MWs of renewable resources. This transition has been supported in part by the Southern Company system retiring 4,226 MWs of coal- and oil-fired generating capacity since 2010 and converting 3,280 MWs of generating capacity from coal to natural gas since 2015. In addition, Southern Company Gas has replaced approximately 5,600 miles of bare steel and cast-iron pipe, resulting in removal of approximately 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 2017 GHG emissions (CO_2 equivalent) were approximately 98 million metric tons, with 2018 emissions estimated at 98 million metric tons. This equates to a reduction of 36% between 2007 and 2018. The 2018 estimates include GHG emissions attributable to each of Elizabethtown Gas, Elkton Gas, Florida City Gas, and the Florida Plants through the date of the applicable disposition. See Note 15 to the financial statements for additional information regarding disposition activities.

In April 2018, Southern Company established an intermediate goal of a 50% reduction in carbon emissions from 2007 levels by 2030 and a long-term goal of low- to no-carbon operations by 2050. To achieve these goals, the Southern Company system expects to continue growing its renewable energy portfolio, optimize technology advancements to modernize its transmission and distribution systems, increase the use of natural gas for generation, complete ongoing construction projects, including Georgia Power's interest in Plant Vogtle Units 3 and 4, invest in energy efficiency, and continue research and development efforts focused on technologies to lower GHG emissions. The Southern Company system's ability to achieve these goals also will be dependent on many external factors, including supportive national energy policies, low natural gas prices, and the development, deployment, and advancement of relevant energy technologies.

FERC Matters

Open Access Transmission Tariff

On May 10, 2018, AMEA and Cooperative Energy filed with the FERC a complaint against SCS and the traditional electric operating companies claiming that the current 11.25% base ROE used in calculating the annual transmission revenue requirements of the traditional electric operating companies' open access transmission tariff is unjust and unreasonable as measured by the applicable FERC standards. The complaint requested that the base ROE be set no higher than 8.65% and that the FERC order refunds for the difference in revenue requirements that results from applying a just and reasonable ROE established in this proceeding upon determining the current ROE is unjust and unreasonable. On June 18, 2018, SCS and the traditional electric operating companies filed their response challenging the adequacy of the showing presented by the complainants and offering support for the current ROE. On September 6, 2018, the FERC issued an order establishing a refund effective date of May 10, 2018 in the event a refund is due and initiating an investigation and settlement procedures regarding the current base ROE. Through December 31, 2018, the estimated maximum potential refund is not expected to be material to Southern Company's results of operations or cash flows. The ultimate outcome of this matter cannot be determined at this time.

Southern Company Gas

Southern Company Gas' gas pipeline investments business is involved in two significant pipeline construction projects, the Atlantic Coast Pipeline (5% ownership) and the PennEast Pipeline (20% ownership), which received FERC approval in October 2017 and January 2018, respectively. Southern Company Gas' total capital expenditures, excluding AFUDC, at completion are expected to be between $350 million and $390 million for the Atlantic Coast Pipeline and $276 million for the PennEast Pipeline. 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.

Work continues with state and federal agencies to obtain the required permits to begin construction on the PennEast Pipeline. Any material delays may impact forecasted capital expenditures and the expected in-service date.

The Atlantic Coast Pipeline has experienced challenges to its permits since construction began in 2018. During the third and fourth quarters 2018, a FERC stop work order, together with delays in obtaining permits necessary for construction and construction delays due to judicial actions, impacted the cost and schedule for the project. As a result, total project cost estimates have increased from between $6.0 billion and $6.5 billion to between $7.0 billion and $7.8 billion, excluding financing costs. Southern Company Gas' share of the total project costs is 5% and Southern Company Gas' investment at December 31, 2018 totaled $83 million. The operator of the joint venture currently expects to achieve a late 2020 in-service date for at least key segments of the Atlantic Coast Pipeline, while the remainder may extend into early 2021. Southern Company Gas has evaluated the recoverability of its investment and determined there was no impairment as of December 31, 2018. Abnormal weather, work delays (including due to judicial or regulatory action), and other conditions may result in additional cost or schedule modifications, which could result in an impairment of Southern Company Gas' investment and could have a material impact on Southern Company's financial statements.

The ultimate outcome of these matters cannot be determined at this time. See Notes 7 and 9 to the financial statements under "Southern Company Gas – Equity Method Investments" and "Guarantees," respectively, for additional information on these pipeline projects.

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 2 to the financial statements under "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 common equity return (WCER) 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%. When the projected WCER is under the allowed range, there is

an adjusting point of 5.98% and eligibility for a performance-based adder of seven basis points, or 0.07%, to the WCER 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. If Alabama Power's actual retail return is above the allowed WCER 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 WCER range. Prior to January 2019, retail rates remained unchanged when the WCER range was between 5.75% and 6.21%.

On May 1, 2018, the Alabama PSC approved modifications to Rate RSE and other commitments designed to position Alabama Power to address the growing pressure on its credit quality resulting from the Tax Reform Legislation, without increasing retail rates under Rate RSE in the near term. Alabama Power plans to reduce growth in total debt by increasing equity, with corresponding reductions in debt issuances, thereby de-leveraging its capital structure. Alabama Power's goal is to achieve an equity ratio of approximately 55% by the end of 2025. At December 31, 2018, Alabama Power's equity ratio was approximately 47%.

The approved modifications to Rate RSE began for billings in January 2019. The modifications include reducing the top of the allowed WCER range from 6.21% to 6.15% and modifications to the refund mechanism applicable to prior year actual results. The modifications to the refund mechanism allow Alabama Power to retain a portion of the revenue that causes the actual WCER for a given year to exceed the allowed range.

Generally, if Alabama Power's actual WCER is between 6.15% and 7.65%, customers will receive 25% of the amount between 6.15% and 6.65%, 40% of the amount between 6.65% and 7.15%, and 75% of the amount between 7.15% and 7.65%. Customers will receive all amounts in excess of an actual WCER of 7.65%.

In conjunction with these modifications to Rate RSE, on May 8, 2018, Alabama Power consented to a moratorium on any upward adjustments under Rate RSE for 2019 and 2020 and will also return $50 million to customers through bill credits in 2019.

On November 30, 2018, Alabama Power made its required annual Rate RSE submission to the Alabama PSC of projected data for calendar year 2019. Projected earnings were within the specified range; therefore, retail rates under Rate RSE remain unchanged for 2019.

At December 31, 2018, Alabama Power's retail return exceeded the allowed WCER range, which resulted in Alabama Power establishing a regulatory liability of $109 million for Rate RSE refunds. In accordance with an Alabama PSC order issued on February 5, 2019, Alabama Power will apply $75 million to reduce the Rate ECR under recovered balance and the remaining $34 million will be refunded to customers through bill credits in July through September 2019.

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. No adjustments to Rate CNP PPA occurred during the period 2016 through 2018 and no adjustment is expected in 2019.

In accordance with an accounting order issued in February 2017 by the Alabama PSC, Alabama Power reclassified $69 million of the December 31, 2016 Rate CNP PPA under recovered balance 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 no later than 2022.

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 in February 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 no later than 2022.

On November 30, 2018, Alabama Power submitted calculations associated with its cost of complying with environmental mandates, as provided under Rate CNP Compliance. The filing reflected a projected unrecovered retail revenue requirement for environmental compliance of approximately $205 million, which is being recovered in the billing months of January 2019 through December 2019.

Tax Reform Accounting Order

On May 1, 2018, the Alabama PSC approved an accounting order that authorized Alabama Power to defer the benefits of federal excess deferred income taxes associated with the Tax Reform Legislation for the year ended December 31, 2018 as a regulatory liability and to use up to $30 million of such deferrals to offset under recovered amounts under Rate ECR. The estimated deferrals for the year ended December 31, 2018 totaled approximately $63 million, subject to adjustment following the filing of the 2018 tax return, of which $30 million was used to offset the Rate ECR under recovered balance and $33 million is recorded in other regulatory liabilities, deferred on the balance sheet to be used for the benefit of customers as determined by the Alabama PSC at a future date. See Note 10 to the financial statements under "Current and Deferred Income Taxes" for additional information.

Environmental Accounting Order

Based on an order from the Alabama PSC (Environmental Accounting Order), 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 is being amortized and recovered over the affected unit's remaining useful life, as established prior to the decision regarding early retirement through Rate CNP Compliance. At December 31, 2018, this regulatory asset had a balance of $42 million. See "Environmental Matters – Environmental Laws and Regulations" herein for additional information regarding environmental regulations.

Subsequent to December 31, 2018, Alabama Power determined that Plant Gorgas Units 8, 9, and 10 (approximately 1,000 MWs) will be retired by April 15, 2019 due to the expected costs of compliance with federal and state environmental regulations. In accordance with the Environmental Accounting Order, approximately $740 million of net investment costs will be transferred to a regulatory asset at the retirement date and recovered over the affected units' remaining useful lives, as established prior to the decision to retire.

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. Georgia Power is scheduled to file a base rate case by July 1, 2019, which may continue or modify these tariffs. In addition, financing costs on certified construction costs 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 2 to the financial statements under "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 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 will retain its merger savings, net of transition costs, as defined in the settlement agreement; through December 31, 2022, such net merger savings will be shared on a 60/40 basis with customers; thereafter, all merger savings will be retained by customers. See Note 15 to the financial statements under "Southern Company Merger with Southern Company Gas" for additional information regarding the Merger.

There were no changes to Georgia Power's traditional base tariff rates, ECCR tariff, DSM tariffs, or MFF tariff in 2017 or 2018.

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 2016, Georgia Power's retail ROE exceeded 12.00%, and Georgia Power refunded to retail customers in 2018 approximately $40 million as approved by the Georgia PSC. On February 5, 2019, the Georgia PSC approved a settlement between Georgia Power and the staff

of the Georgia PSC under which Georgia Power's retail ROE for 2017 was stipulated to exceed 12.00% and Georgia Power will reduce certain regulatory assets by approximately $4 million in lieu of providing refunds to retail customers. In 2018, Georgia Power's retail ROE exceeded 12.00%, and Georgia Power accrued approximately $100 million to refund to retail customers, subject to review and approval by the Georgia PSC.

On April 3, 2018, the Georgia PSC approved the Georgia Power Tax Reform Settlement Agreement. Pursuant to the Georgia Power Tax Reform Settlement Agreement, to reflect the federal income tax rate reduction impact of the Tax Reform Legislation, Georgia Power will refund to customers a total of $330 million through bill credits. Georgia Power issued bill credits of approximately $130 million in 2018 and will issue bill credits of approximately $95 million in June 2019 and $105 million in February 2020. In addition, Georgia Power is deferring as a regulatory liability (i) the revenue equivalent of the tax expense reduction resulting from legislation lowering the Georgia state income tax rate from 6.00% to 5.75% in 2019 and (ii) the entire benefit of federal and state excess accumulated deferred income taxes, which is expected to total approximately $700 million at December 31, 2019. At December 31, 2018, the related regulatory liability balance totaled $610 million. The amortization of these regulatory liabilities is expected to be addressed in the Georgia Power 2019 Base Rate Case. If there is not a base rate case in 2019, customers will receive $185 million in annual bill credits beginning in 2020, with any additional federal and state income tax savings deferred as a regulatory liability, until Georgia Power's next base rate case.

To address some of the negative cash flow and credit quality impacts of the Tax Reform Legislation, the Georgia PSC also approved an increase in Georgia Power's retail equity ratio to the lower of (i) Georgia Power's actual common equity weight in its capital structure or (ii) 55%, until the Georgia Power 2019 Base Rate Case. At December 31, 2018, Georgia Power's actual retail common equity ratio (on a 13-month average basis) was approximately 55%. Benefits from reduced federal income tax rates in excess of the amounts refunded to customers will be retained by Georgia Power to cover the carrying costs of the incremental equity in 2018 and 2019.

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 2016, the Georgia PSC approved Georgia Power's triennial Integrated Resource Plan (2016 IRP) including 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 Georgia Power 2019 Base Rate Case.

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. In March 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 the Georgia Power 2019 Base Rate Case.

On January 31, 2019, Georgia Power filed its triennial IRP (2019 IRP). The filing includes a request to decertify and retire Plant Hammond Units 1 through 4 (840 MWs) and Plant McIntosh Unit 1 (142.5 MWs) upon approval of the 2019 IRP.

In the 2019 IRP, Georgia Power requested approval to reclassify the remaining net book value of Plant Hammond Units 1 through 4 (approximately $520 million at December 31, 2018) upon retirement to a regulatory asset to be amortized ratably over a period equal to the applicable unit's remaining useful life through 2035. For Plant McIntosh Unit 1, Georgia Power requested approval to reclassify the remaining net book value (approximately $40 million at December 31, 2018) upon retirement to a regulatory asset to be amortized over a three-year period to be determined in the Georgia Power 2019 Base Rate Case. Georgia Power also requested approval to reclassify any unusable material and supplies inventory balances remaining at the applicable unit's retirement date to a regulatory asset for recovery over a period to be determined in the Georgia Power 2019 Base Rate Case.

The 2019 IRP also includes a request to certify approximately 25 MWs of capacity at Plant Scherer Unit 3 for the retail jurisdiction beginning January 1, 2020, following the expiration of a wholesale PPA.

The 2019 IRP also includes details regarding ARO costs associated with ash pond and landfill closures and post-closure care. Georgia Power requested the timing and rate of recovery of these costs be determined by the Georgia PSC in the Georgia Power 2019 Base Rate Case. See "Environmental Matters – Environmental Laws and Regulations – Coal Combustion Residuals" and FINANCIAL CONDITION AND LIQUIDITY – "Capital Requirements and Contractual Obligations" herein and Note 6 to the financial statements for additional information regarding Georgia Power's AROs.

Georgia Power also requested approval to issue two capacity-based requests for proposals (RFP). If approved, the first capacity-based RFP will seek resources that can provide capacity beginning in 2022 or 2023 and the second capacity-based RFP will seek resources that can provide capacity beginning in 2026, 2027, or 2028. Additionally, the 2019 IRP includes a request to procure an additional 1,000 MWs of renewable resources through a competitive bidding process. Georgia Power also proposed to invest in a portfolio of up to 50 MWs of battery energy storage technologies.

A decision from the Georgia PSC on the 2019 IRP is expected in mid-2019.

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

Storm Damage Recovery

Georgia Power is accruing $30 million annually through December 31, 2019, as provided in the 2013 ARP, for incremental operations and maintenance costs of damage from major storms to its transmission and distribution facilities. At December 31, 2018, the total balance in the regulatory asset related to storm damage was $416 million. During October 2018, Hurricane Michael caused significant damage to Georgia Power's transmission and distribution facilities. The incremental restoration costs related to this hurricane deferred in the regulatory asset for storm damage totaled approximately $115 million. Hurricanes Irma and Matthew also caused significant damage to Georgia Power's transmission and distribution facilities during September 2017 and October 2016, respectively. The incremental restoration costs related to Hurricanes Irma and Matthew deferred in Georgia Power's regulatory asset for storm damage totaled approximately $250 million. The rate of storm damage cost recovery is expected to be adjusted as part of the Georgia Power 2019 Base Rate Case and further adjusted in future regulatory proceedings as necessary. The ultimate outcome of this matter cannot be determined at this time. See Note 2 to the financial statements under "Georgia Power – Storm Damage Recovery" for additional information regarding Georgia Power's storm damage reserve.

Mississippi Power

Mississippi Power's retail base rates generally 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.

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 requested an increase of $26 million in annual revenues, based on a performance adjusted ROE of 9.33% and an increased equity ratio of 55%. On July 27, 2018, Mississippi Power and the MPUS entered into a settlement agreement with respect to the 2018 PEP filing and all unresolved PEP filings for prior years (PEP Settlement Agreement), which was approved by the Mississippi PSC on August 7, 2018. Rates under the PEP Settlement Agreement became effective with the first billing cycle of September 2018. The PEP Settlement Agreement provides for an increase of approximately $21.6 million in annual base retail revenues, which excludes certain compensation costs contested by the MPUS, as well as approximately $2 million which was subsequently approved for recovery through Mississippi Power's 2018 Energy Efficiency Cost Rider.

Pursuant to the PEP Settlement Agreement, Mississippi Power's performance-adjusted allowed ROE is 9.31% and its allowed equity ratio is capped at 51%, pending further review by the Mississippi PSC. In lieu of the requested equity ratio increase, Mississippi Power retained $44 million of excess accumulated deferred income taxes resulting from the Tax Reform Legislation until the conclusion of Mississippi Power's next base rate case, which is scheduled to be filed in the fourth quarter 2019 (Mississippi Power 2019 Base Rate Case). Further, Mississippi Power agreed to seek equity contributions sufficient to restore its equity ratio to 50% by December 31, 2018.

Pursuant to the PEP Settlement Agreement, PEP proceedings are suspended until after the conclusion of the Mississippi Power 2019 Base Rate Case and Mississippi Power is not required to make any PEP filings for regulatory years 2018, 2019, and 2020. The PEP Settlement Agreement also resolved all open PEP filings with no change to customer rates.

Kemper County Energy Facility

In 2018, Mississippi Power recorded pre-tax charges to income of $37 million ($27 million after tax), primarily resulting from the abandonment and related closure activities and ongoing period costs, net of sales proceeds, for the mine and gasifier-related assets at the Kemper County energy facility. In addition, Mississippi Power recorded a credit to earnings of $95 million in the fourth quarter 2018 primarily resulting from the reduction of a valuation allowance for a state income tax net operating loss (NOL) carryforward associated with the Kemper County energy facility. Additional closure costs for the mine and gasifier-related assets, currently estimated at up to $10 million pre-tax (excluding salvage, net of dismantlement costs), may be incurred through the first half of 2020. In addition, period costs, including, but not limited to, costs for compliance and safety, ARO accretion, and property taxes for the mine and gasifier-related assets, are estimated to total $11 million in 2019 and $2 million to $4 million annually in

2020 through 2023. Mississippi Power is currently evaluating its options regarding the final disposition of the CO_2 pipeline, including removal of the pipeline. This evaluation is expected to be complete later in 2019. If Mississippi Power ultimately decides to remove the CO_2 pipeline, the cost of removal could have a material impact on Southern Company's financial statements. The ultimate outcome of these matters cannot be determined at this time.

The combined cycle and associated common facilities portions of the Kemper County energy facility were dedicated as Plant Ratcliffe on April 27, 2018.

For additional information on the Kemper County energy facility, see Note 2 to the financial statements under "Mississippi Power – Kemper County Energy Facility."

Reserve Margin Plan

On August 6, 2018, Mississippi Power filed its proposed Reserve Margin Plan (RMP), as required by the Mississippi PSC's order in the docket established for the purposes of pursuing a global settlement of the costs related to the Kemper County energy facility. Under the RMP, Mississippi Power proposed alternatives that would reduce its reserve margin, with the most economic of the alternatives being the two-year and seven-year acceleration of the retirement of Plant Watson Units 4 and 5, respectively, to the first quarter 2022 and the four-year acceleration of the retirement of Plant Greene County Units 1 and 2 to the third quarter 2021 and the third quarter 2022, respectively, in order to lower or avoid operating costs. The Plant Greene County unit retirements would require the completion by Alabama Power of proposed transmission and system reliability improvements, as well as agreement by Alabama Power. The RMP filing also states that, in the event the Mississippi PSC ultimately approves an alternative that includes an accelerated retirement, Mississippi Power would require authorization to defer in a regulatory asset for future recovery the remaining net book value of the units at the time of retirement. A decision by the Mississippi PSC that does not include recovery of the remaining book value of any generating units retired could have a material impact on Southern Company's financial statements. The ultimate outcome of this matter cannot be determined at this time.

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. Through December 31, 2018, Mississippi Power received total DOE grants of $387 million, of which $382 million reduced the construction costs of the Kemper County energy facility and $5 million reimbursed Mississippi Power for expenses associated with DOE reporting. On December 12, 2018, Mississippi Power filed with the DOE its request for property closeout certification under the contract related to the grants received. Mississippi Power and the DOE are currently in discussions regarding the requested closeout and property disposition, which may require payment to the DOE for a portion of certain property that is to be retained by Mississippi Power. The ultimate outcome of this matter cannot be determined at this time; however, it could have a significant impact on Southern Company's financial statements.

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.

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.

Infrastructure Replacement Programs and Capital Projects

In addition to capital expenditures recovered through base rates by each of the natural gas distribution utilities, Nicor Gas and Virginia Natural Gas have separate rate riders that provide timely recovery of capital expenditures for specific infrastructure replacement programs. These infrastructure replacement programs and capital projects are risk-based and designed to update and replace cast iron, bare steel, and mid-vintage plastic materials or expand the natural gas distribution systems to improve reliability and meet operational flexibility and growth. The total expected investment under the infrastructure replacement programs for 2019 is $408 million. See Note 2 to the financial statements under "Southern Company Gas – Infrastructure Replacement Programs and Capital Projects" for additional information.

Rate Proceedings

On February 23, 2018, Atlanta Gas Light revised its annual base rate filing to reflect the impacts of the Tax Reform Legislation and requested a $16 million rate reduction in 2018. On May 15, 2018, the Georgia PSC approved a stipulation for Atlanta Gas Light's annual base rates to remain at the 2017 level for 2018 and 2019, with customer credits of $8 million in each of July 2018 and October 2018 to reflect the impacts of the Tax Reform Legislation. The Georgia PSC maintained Atlanta Gas Light's previously authorized earnings band based on a ROE between 10.55% and 10.95% and increased the allowed equity ratio by 4% to an equity ratio of 55% to address the negative cash flow and credit metric impacts of the Tax Reform Legislation. Additionally, Atlanta Gas Light is required to file a traditional base rate case on or before June 1, 2019 for rates effective January 1, 2020.

On January 31, 2018, the Illinois 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%.

On May 2, 2018, the Illinois Commission approved Nicor Gas' rehearing request for revised base rates to incorporate the reduction in the federal income tax rate as a result of the Tax Reform Legislation. The resulting decrease of approximately $44 million in annual base rate revenues became effective May 5, 2018. Nicor Gas' previously-authorized capital structure and ROE of 9.80% were not addressed in the rehearing and remain unchanged. On November 9, 2018, Nicor Gas filed a general base rate case with the Illinois Commission requesting a $230 million increase in annual base rate revenues. The requested increase is based on a projected test year for the 12-month period ending September 30, 2020, a ROE of 10.6%, and an increase in the equity ratio from 52.0% to 54.0% to address the negative cash flow and credit metric impacts of the Tax Reform Legislation. The Illinois Commission is expected to rule on the requested increase within the 11-month statutory time limit, after which rate adjustments will be effective. The ultimate outcome of this matter 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 2 to the financial statements under "Alabama Power – Rate ECR," "Georgia Power – Fuel Cost Recovery," and "Mississippi Power – Fuel Cost Recovery" for additional information.

Construction Program

Overview

The subsidiary companies of Southern Company are engaged in continuous construction programs to accommodate existing and estimated future loads on their respective systems. The Southern Company system intends to continue its strategy of developing and constructing new electric generating facilities, adding environmental modifications to certain existing units, expanding and improving 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. See Note 15 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 and Note 2 to the financial statements under "Southern Company Gas – Infrastructure Replacement

Programs and Capital Projects" for additional information regarding infrastructure improvement programs at the natural gas distribution utilities.

The Southern Company system's construction program is currently estimated to total approximately $8.0 billion, $7.7 billion, $6.7 billion, $6.3 billion, and $6.0 billion for 2019, 2020, 2021, 2022, and 2023, 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 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

In 2009, the Georgia PSC certified construction of Plant Vogtle Units 3 and 4. Georgia Power holds a 45.7% ownership interest in 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. In March 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 in July 2017 when Georgia Power, acting for itself and as agent for the other Vogtle Owners, and the EPC Contractor entered into the Vogtle Services Agreement. Under the Vogtle Services Agreement, Westinghouse provides facility design and engineering services, procurement and technical support, and staff augmentation on a time and materials cost basis. The Vogtle Services Agreement provides that it 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.

In October 2017, Georgia Power, acting for itself and as agent for the other Vogtle Owners, executed the Bechtel Agreement, a cost reimbursable plus fee arrangement, whereby Bechtel is 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.

Cost and Schedule

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

		(in billions)
Base project capital cost forecast[(a)(b)]	$	8.0
Construction contingency estimate		0.4
Total project capital cost forecast[(a)(b)]		8.4
Net investment as of December 31, 2018[(b)]		(4.6)
Remaining estimate to complete[(a)]	**$**	**3.8**

(a) Excludes financing costs expected to be capitalized through AFUDC of approximately $315 million.

(b) Net of $1.7 billion received from Toshiba under the Guarantee Settlement Agreement and approximately $188 million in related 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 $1.9 billion had been incurred through December 31, 2018.

As construction continues, challenges with management of contractors, subcontractors, and vendors; labor productivity, availability, and/or cost escalation; procurement, fabrication, delivery, assembly, and/or installation and testing, including any

required engineering changes, of plant systems, structures, and components (some of which are based on new technology that only recently began initial operation in the global nuclear industry at this scale); or other issues could arise and change the projected schedule and estimated cost. Monthly construction production targets required to maintain the current project schedule will continue to increase significantly throughout 2019. To meet these increasing monthly targets, existing craft construction productivity must improve and additional craft laborers must be retained and deployed.

Georgia Power and Southern Nuclear believe it is a leading practice in connection with a construction project of this size and complexity to periodically validate recent construction progress in comparison to the projected schedule and to verify and update quantities of commodities remaining to install, labor productivity, and forecasted staffing needs. This verification process, led by Southern Nuclear, was underway as of December 31, 2018 and is expected to be completed during the second quarter 2019. Georgia Power currently does not anticipate any material changes to the total estimated project capital cost forecast for Plant Vogtle Units 3 and 4 or the expected in-service dates of November 2021 and November 2022, respectively, resulting from this verification process. However, the ultimate impact on cost and schedule, if any, will not be known until the verification process is completed. Georgia Power is required to report the results and any project impacts to the Georgia PSC by May 15, 2019.

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 ITAAC 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. However, any extension of the project schedule is currently estimated to result in additional base capital costs of approximately $50 million per month, based on Georgia Power's ownership interests, and AFUDC of approximately $12 million per month. While Georgia Power is not precluded from seeking recovery of any future capital cost forecast increase, management will ultimately determine whether or not to seek recovery. Any further changes to the capital cost forecast that are not expected to be recoverable through regulated rates will be required to be charged to income and such charges could be material.

Joint Owner Contracts

In November 2017, the Vogtle Owners entered into an amendment to their joint ownership agreements for Plant Vogtle Units 3 and 4 to provide for, among other conditions, additional Vogtle Owner approval requirements. Effective August 31, 2018, the Vogtle Owners further amended the joint ownership agreements to clarify and provide procedures for certain provisions of the joint ownership agreements related to adverse events that require the vote of the holders of at least 90% of the ownership interests in Plant Vogtle Units 3 and 4 to continue construction (as amended, and together with the November 2017 amendment, the Vogtle Joint Ownership Agreements). 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.

As a result of the increase in the total project capital cost forecast and Georgia Power's decision not to seek rate recovery of the increase in the base capital costs as described below, the holders of at least 90% of the ownership interests in Plant Vogtle Units 3 and 4 were required to vote to continue construction. On September 26, 2018, the Vogtle Owners unanimously voted to continue construction of Plant Vogtle Units 3 and 4.

Amendments to the Vogtle Joint Ownership Agreements

In connection with the vote to continue construction, Georgia Power entered into (i) the Vogtle Owner Term Sheet with the other Vogtle Owners and MEAG's wholly-owned subsidiaries MEAG SPVJ, MEAG Power SPVM, LLC (MEAG SPVM), and MEAG Power SPVP, LLC (MEAG SPVP) to take certain actions which partially mitigate potential financial exposure for the other Vogtle Owners, including additional amendments to the Vogtle Joint Ownership Agreements and the purchase of PTCs from the other Vogtle Owners, and (ii) the MEAG Term Sheet with MEAG and MEAG SPVJ to provide funding with respect to MEAG SPVJ's ownership interest in Plant Vogtle Units 3 and 4 (Project J) under certain circumstances. On January 14, 2019, Georgia Power, MEAG, and MEAG SPVJ entered into an agreement to implement the provisions of the MEAG Term Sheet (MEAG Funding Agreement). On February 18, 2019, Georgia Power, the other Vogtle Owners, and MEAG's wholly-owned subsidiaries MEAG SPVJ, MEAG SPVM, and MEAG SPVP entered into certain amendments to the Vogtle Joint Ownership Agreements to implement the provisions of the Vogtle Owner Term Sheet (Global Amendments).

Pursuant to the Global Amendments, and consistent with the Vogtle Owner Term Sheet, the Vogtle Joint Ownership Agreements were modified as follows: (i) each Vogtle Owner must pay its proportionate share of qualifying construction costs for Plant Vogtle Units 3 and 4 based on its ownership percentage up to the estimated cost at completion (EAC) for Plant Vogtle Units 3 and 4 which formed the basis of Georgia Power's forecast of $8.4 billion in the nineteenth VCM plus $800 million; (ii) Georgia Power will be responsible for 55.7% of actual qualifying construction costs between $800 million and $1.6 billion over the EAC in the nineteenth VCM (resulting in $80 million of potential additional costs to Georgia Power), with the remaining Vogtle Owners responsible for 44.3% of such costs pro rata in accordance with their respective ownership interests; and (iii) Georgia Power will be responsible for 65.7% of qualifying construction costs between $1.6 billion and $2.1 billion over the EAC in the nineteenth VCM (resulting in a further $100 million of potential additional costs to Georgia Power), with the remaining Vogtle Owners responsible for 34.3% of such costs pro rata in accordance with their respective ownership interests.

If the EAC is revised and exceeds the EAC in the nineteenth VCM by more than $2.1 billion, each of the other Vogtle Owners will have a one-time option at the time the project budget forecast is so revised to tender a portion of its ownership interest to Georgia Power in exchange for Georgia Power's agreement to pay 100% of such Vogtle Owner's remaining share of total construction costs in excess of the EAC in the nineteenth VCM plus $2.1 billion. In this event, Georgia Power will have the option of cancelling the project in lieu of purchasing a portion of the ownership interest of any other Vogtle Owner. If Georgia Power accepts the offer to purchase a portion of another Vogtle Owner's ownership interest in Plant Vogtle Units 3 and 4, the ownership interest(s) to be conveyed from the tendering Vogtle Owner(s) to Georgia Power will be calculated based on the proportion of the cumulative amount of construction costs paid by each such tendering Vogtle Owner(s) and by Georgia Power as of the COD of Plant Vogtle Unit 4. For purposes of this calculation, payments made by Georgia Power on behalf of another Vogtle Owner in accordance with the second and third items described in the paragraph above will be treated as payments made by the applicable Vogtle Owner.

In the event the actual costs of construction at completion of a Unit are less than the EAC reflected in the nineteenth VCM report and such Unit is placed in service in accordance with the schedule projected in the nineteenth VCM report (i.e., Plant Vogtle Unit 3 is placed in service by November 2021 or Plant Vogtle Unit 4 is placed in service by November 2022), Georgia Power will be entitled to 60.7% of the cost savings with respect to the relevant Unit and the remaining Vogtle Owners will be entitled to 39.3% of such savings on a pro rata basis in accordance with their respective ownership interests.

For purposes of the foregoing provisions, qualifying construction costs will not include costs (i) resulting from force majeure events, including governmental actions or inactions (or significant delays associated with issuance of such actions) that affect the licensing, completion, start-up, operations, or financing of Plant Vogtle Units 3 and 4, administrative proceedings or litigation regarding ITAAC or other regulatory challenges to commencement of operation of Plant Vogtle Units 3 and 4, and changes in laws or regulations governing Plant Vogtle Units 3 and 4, (ii) legal fees and legal expenses incurred due to litigation with contractors or subcontractors that are not subsidiaries or affiliates of Southern Company, and (iii) additional costs caused by requests from the Vogtle Owners other than Georgia Power, except for the exercise of a right to vote granted under the Vogtle Joint Ownership Agreements, that increase costs by $100,000 or more.

Pursuant to the Global Amendments, and consistent with the Vogtle Owner Term Sheet, the provisions of the Vogtle Joint Ownership Agreements requiring that Vogtle Owners holding 90% of the ownership interests in Plant Vogtle Units 3 and 4 vote to continue construction following certain adverse events (Project Adverse Events) were modified. Pursuant to the Global Amendments, the holders of at least 90% of the ownership interests in Plant Vogtle Units 3 and 4 must vote to continue construction if certain Project Adverse Events occur, including: (i) the bankruptcy of Toshiba; (ii) the termination or rejection in bankruptcy of certain agreements, including the Vogtle Services Agreement, the Bechtel Agreement, or the agency agreement with Southern Nuclear; (iii) Georgia Power publicly announces its intention not to submit for rate recovery any portion of its investment in Plant Vogtle Units 3 and 4 or the Georgia PSC 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, excluding any additional amounts paid by Georgia Power on behalf of the other Vogtle Owners pursuant to the Global Amendments described above and the first 6% of costs during any six-month VCM reporting period that are disallowed by the Georgia PSC for recovery, or for which Georgia Power elects not to seek cost recovery, through retail rates; and (iv) an incremental extension of one year or more over the most recently approved schedule. Under the Global Amendments, Georgia Power may cancel the project at any time in its sole discretion.

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 Global Amendments provide that if the holders of at least 90% of the ownership interests fail to vote in favor of continuing the project following any future Project Adverse Event, work on Plant Vogtle Units 3 and 4 will continue for a period of 30 days if

the holders of more than 50% of the ownership interests vote in favor of continuing construction (Majority Voting Owners). In such a case, the Vogtle Owners (i) have agreed to negotiate in good faith towards the resumption of the project, (ii) if no agreement is reached during such 30-day period, the project will be cancelled, and (iii) in the event of such a cancellation, the Majority Voting Owners will be obligated to reimburse any other Vogtle Owner for the incremental costs it incurred during such 30-day negotiation period.

Purchase of PTCs During Commercial Operation

Pursuant to the Global Amendments, and consistent with the Vogtle Owner Term Sheet, Georgia Power has agreed to purchase additional PTCs from OPC, Dalton, MEAG SPVM, MEAG SPVP, and MEAG SPVJ (to the extent any MEAG SPVJ PTC rights remain after any purchases required under the MEAG Funding Agreement as described below) at varying purchase prices dependent upon the actual cost to complete construction of Plant Vogtle Units 3 and 4 as compared to the EAC reflected in the nineteenth VCM report. The purchases are at the option of the applicable Vogtle Owner.

Potential Funding to MEAG Project J

Pursuant to the MEAG Funding Agreement, and consistent with the MEAG Term Sheet, if MEAG SPVJ is unable to make its payments due under the Vogtle Joint Ownership Agreements solely as a result of the occurrence of one of the following situations that materially impedes access to capital markets for MEAG for Project J: (i) the conduct of JEA or the City of Jacksonville, such as JEA's legal challenges of its obligations under a PPA with MEAG (PPA-J), or (ii) PPA-J is declared void by a court of competent jurisdiction or rejected by JEA under the applicable provisions of the U.S. Bankruptcy Code (each of (i) and (ii), a JEA Default), at MEAG's request, Georgia Power will purchase from MEAG SPVJ the rights to PTCs attributable to MEAG SPVJ's share of Plant Vogtle Units 3 and 4 (approximately 206 MWs) within 30 days of such request at varying prices dependent upon the stage of construction of Plant Vogtle Units 3 and 4. The aggregate purchase price of the PTCs, together with any advances made as described in the next paragraph, shall not exceed $300 million.

At the option of MEAG, as an alternative or supplement to Georgia Power's purchase of PTCs as described above, Georgia Power has agreed to provide up to $250 million in funding to MEAG for Project J in the form of advances (either advances under the Vogtle Joint Ownership Agreements or the purchase of MEAG Project J bonds, at the discretion of Georgia Power), subject to any required approvals of the Georgia PSC and the DOE.

In the event MEAG SPVJ certifies to Georgia Power that it is unable to fund its obligations under the Vogtle Joint Ownership Agreements as a result of a JEA Default and Georgia Power becomes obligated to provide funding as described above, MEAG is required to (i) assign to Georgia Power its right to vote on any future Project Adverse Event and (ii) diligently pursue JEA for its breach of PPA-J. In addition, Georgia Power agreed that it will not sue MEAG for any amounts due from MEAG SPVJ under MEAG's guarantee of MEAG SPVJ's obligations so long as MEAG SPVJ complies with the terms of the MEAG Funding Agreement as to its payment obligations and the other non-payment provisions of the Vogtle Joint Ownership Agreements.

Under the terms of the MEAG Funding Agreement, Georgia Power may cancel the project in lieu of providing funding in the form of advances or PTC purchases.

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

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 Plant Vogtle Units 3 and 4. 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. At December 31, 2018, Georgia Power had recovered approximately $1.9 billion of financing costs. Financing costs related to capital costs above $4.418 billion will be recovered through AFUDC; however, Georgia Power will not record AFUDC related to any capital costs in excess of the total deemed reasonable by the Georgia PSC (currently $7.3 billion) and not requested for rate recovery. On December 18, 2018, the Georgia PSC approved Georgia Power's request to increase the NCCR tariff by $88 million annually, effective January 1, 2019.

Georgia Power is required to file semi-annual VCM reports with the Georgia PSC by February 28 and August 31 of each year. In 2013, in connection with the eighth VCM report, the Georgia PSC approved a 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.

In 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. In December 2017, the Georgia PSC voted to approve (and issued its related order on January 11, 2018) Georgia Power's seventeenth VCM report, which included a recommendation to continue construction with Southern Nuclear as project manager and Bechtel serving as the primary construction contractor, and modified 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 $5.68 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 $5.68 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 related Customer Refunds) was 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 $100 million, $25 million, and $20 million in 2018, 2017, and 2016, respectively, and are estimated to have negative earnings impacts of approximately $75 million in 2019 and an aggregate of approximately $615 million from 2020 to 2022.

In its January 11, 2018 order, the Georgia PSC also stated if other conditions change and assumptions upon which Georgia Power's seventeenth VCM report are based do not materialize, the Georgia PSC reserved the right to reconsider the decision to continue construction.

On February 12, 2018, Georgia Interfaith Power & Light, Inc. (GIPL) and Partnership for Southern Equity, Inc. (PSE) filed a petition appealing the Georgia PSC's January 11, 2018 order with the Fulton County Superior Court. On March 8, 2018, Georgia Watch filed a similar appeal to the Fulton County Superior Court for judicial review of the Georgia PSC's decision and denial of Georgia Watch's motion for reconsideration. On December 21, 2018, the Fulton County Superior Court granted Georgia Power's motion to dismiss the two appeals. On January 9, 2019, GIPL, PSE, and Georgia Watch filed an appeal of this decision with the Georgia Court of Appeals. Georgia Power believes the appeal has no merit; however, an adverse outcome in the appeal combined with subsequent adverse action by the Georgia PSC could have a material impact on Southern Company's results of operations, financial condition, and liquidity.

In preparation for its nineteenth VCM filing, Georgia Power requested Southern Nuclear to perform a full cost reforecast for the project. This reforecast, performed prior to the nineteenth VCM filing, resulted in a $0.7 billion increase to the base capital cost forecast reported in the second quarter 2018. This base cost increase primarily resulted from changed assumptions related to the finalization of contract scopes and management responsibilities for Bechtel and over 60 subcontractors, labor productivity rates, and craft labor incentives, as well as the related levels of project management, oversight, and support, including field supervision and engineering support.

Although Georgia Power believes these incremental costs are reasonable and necessary to complete the project and the Georgia PSC's order in the seventeenth VCM proceeding specifically states that the construction of Plant Vogtle Units 3 and 4 is not subject to a cost cap, Georgia Power did not seek rate recovery for these cost increases included in the current base capital cost forecast (or any related financing costs) in the nineteenth VCM report. In connection with future VCM filings, Georgia Power may request the Georgia PSC to evaluate costs currently included in the construction contingency estimate for rate recovery as and when they are appropriately included in the base capital cost forecast. After considering the significant level of uncertainty that exists regarding the future recoverability of costs included in the construction contingency estimate since the ultimate outcome of these matters is subject to the outcome of future assessments by management, as well as Georgia PSC decisions in these future regulatory proceedings, Georgia Power recorded a total pre-tax charge to income of $1.1 billion ($0.8 billion after

tax) in the second quarter 2018, which includes the total increase in the base capital cost forecast and construction contingency estimate.

On August 31, 2018, Georgia Power filed its nineteenth VCM report with the Georgia PSC, which requested approval of $578 million of construction capital costs incurred from January 1, 2018 through June 30, 2018. On February 19, 2019, the Georgia PSC approved the nineteenth VCM, but deferred approval of $51.6 million of expenditures related to Georgia Power's portion of an administrative claim filed in the Westinghouse bankruptcy proceedings. Through the nineteenth VCM, the Georgia PSC has approved total construction capital costs incurred through June 30, 2018 of $5.4 billion (before $1.7 billion of payments received under the Guarantee Settlement Agreement and approximately $188 million in related Customer Refunds). In addition, the staff of the Georgia PSC requested, and Georgia Power agreed, to file its twentieth VCM report concurrently with the twenty-first VCM report by August 31, 2019.

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

DOE Financing

At December 31, 2018, 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. In September 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. In September 2018, the DOE extended the conditional commitment to March 31, 2019. Any further extension must be 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 8 to the financial statements under "Long-term Debt – DOE Loan Guarantee Borrowings" for additional information, including applicable covenants, events of default, mandatory prepayment events (including any decision not to continue construction of Plant Vogtle Units 3 and 4), and conditions to borrowing.

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

Income Tax Matters

Federal Tax Reform Legislation

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

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 provided 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 considered all amounts recorded in the financial statements as a result of the Tax Reform Legislation "provisional" as discussed in SAB 118 and subject to revision prior to filing its 2017 tax return in the fourth quarter 2018. Southern Company recognized tax benefits of $30 million and $264 million in 2018 and 2017, respectively, for a total net tax benefit of $294 million as a result of the Tax Reform Legislation. In addition, in total, Southern Company recorded a $417 million decrease in regulatory assets and a $6.2 billion increase in regulatory liabilities as a result of the Tax Reform Legislation and $16 million of stranded excess deferred tax balances in AOCI at December 31, 2017 were adjusted through retained earnings in 2018. As of December 31, 2018, Southern Company considered the measurement of impacts from the Tax Reform Legislation on deferred income tax assets and liabilities, primarily due to the impact of the reduction of the corporate income tax rate, to be complete.

However, the IRS continues to issue regulations that provide further interpretation and guidance on the law and each state's adoption of the provisions contained in the Tax Reform Legislation remains uncertain. In addition, the regulatory treatment of certain impacts of the Tax Reform Legislation is subject to the discretion of the FERC and each state's regulatory commission. The ultimate impact of these matters cannot be determined at this time. See Note 2 to the financial statements for additional information regarding the traditional electric operating companies' and the natural gas distribution utilities' rate filings, including

amounts returned to customers during 2018, to reflect the impacts of the Tax Reform Legislation. Also see FINANCIAL CONDITION AND LIQUIDITY – "Credit Rating Risk" herein and Note 10 to the financial statements under "Current and Deferred Income Taxes" for additional information.

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 $300 million for the 2018 tax year and approximately $130 million for the 2019 tax year. The ultimate outcome of this matter 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 commenced 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. Southern 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 Taxes" and Note 10 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.

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 laws and regulations governing air, water, land, and protection of other natural resources. Litigation over environmental issues and claims of various types, including property damage, personal injury, common law nuisance, and citizen enforcement of environmental laws and regulations, 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 Notes 2 and 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 Notes 2 and 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.

Litigation

In January 2017, a putative 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. In June 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. In July 2017, the defendants filed a motion to dismiss the plaintiffs' amended complaint with prejudice, to which the plaintiffs filed an opposition in September 2017. On March 29, 2018, the U.S. District Court for the Northern District of Georgia, Atlanta Division, issued an order granting, in part, the defendants' motion to dismiss. The court dismissed certain claims against certain officers of Southern Company and Mississippi Power and dismissed the allegations related to a number of the statements that plaintiffs challenged as being false or misleading. On April 26, 2018, the

defendants filed a motion for reconsideration of the court's order, seeking dismissal of the remaining claims in the lawsuit. On August 10, 2018, the court denied the motion for reconsideration and denied a motion to certify the issue for interlocutory appeal.

In February 2017, Jean Vineyard filed a shareholder derivative lawsuit and, in May 2017, Judy Mesirov filed a shareholder derivative lawsuit, each 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. In August 2017, these two shareholder derivative lawsuits were consolidated in the U.S. District Court for the Northern District of Georgia. The complaints allege that the defendants caused Southern Company to make false or misleading statements regarding the Kemper County energy facility cost and schedule. Further, the complaints allege that the defendants were unjustly enriched and caused the waste of corporate assets and also allege that the individual defendants violated their fiduciary duties. Each plaintiff seeks to recover, on behalf of Southern Company, unspecified actual damages and, on each plaintiff's own behalf, attorneys' fees and costs in bringing the lawsuit. Each plaintiff also seeks certain changes to Southern Company's corporate governance and internal processes. On April 25, 2018, the court entered an order staying this lawsuit until 30 days after the resolution of any dispositive motions or any settlement, whichever is earlier, in the putative securities class action.

In May 2017, Helen E. Piper Survivor's Trust filed a shareholder derivative lawsuit in the Superior Court of Gwinnett County, State 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 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. The 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. The 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. The plaintiff also seeks certain unspecified changes to Southern Company's corporate governance and internal processes. On May 4, 2018, the court entered an order staying this lawsuit until 30 days after the resolution of any dispositive motions or any settlement, whichever is earlier, in the putative securities class action.

On May 18, 2018, Southern Company and Mississippi Power received a notice of dispute and arbitration demand filed by Martin Product Sales, LLC (Martin) based on two agreements, both related to Kemper IGCC byproducts for which Mississippi Power provided termination notices in September 2017. Martin alleges breach of contract, breach of good faith and fair dealing, fraud and misrepresentation, and civil conspiracy and makes a claim for damages in the amount of approximately $143 million, as well as additional unspecified damages, attorney's fees, costs, and interest. In the first quarter 2019, Mississippi Power and Southern Company filed motions to dismiss.

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 2017, the financial and operational performance of one of the lessees and the associated generation assets 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. As a result of operational improvements in 2018, the 2018 lease payments were paid in full. However, operational issues and the resulting cash liquidity challenges persist and significant concerns continue regarding the lessee's ability to make the remaining semi-annual lease payments. These operational challenges may also impact the expected residual value of the assets at the end of the lease term in 2047. If 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 could 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 would result in a reduction in net income of approximately $86 million after tax based on the lease receivable balance at December 31, 2018. 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 at December 31, 2018. 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. The ultimate outcome of this matter cannot be determined at this time.

Mississippi Power

In conjunction with Southern Company's sale of Gulf Power, Mississippi Power and Gulf Power have committed to seek a restructuring of their 50% undivided ownership interests in Plant Daniel such that each of them would, after the restructuring, own 100% of a generating unit. On January 15, 2019, Gulf Power provided notice to Mississippi Power that Gulf Power will retire its share of the generating capacity of Plant Daniel on January 15, 2024. Mississippi Power has the option to purchase Gulf Power's ownership interest for $1 on January 15, 2024, provided that Mississippi Power exercises the option no later than 120 days prior to that date. Mississippi Power is assessing the potential operational and economic effects of Gulf Power's notice. The ultimate outcome of these matters remains subject to completion of Mississippi Power's evaluations and applicable regulatory approvals, including the FERC and the Mississippi PSC, and cannot now be determined. See Note 15 to the financial statements under "Southern Company's Sale of Gulf Power" for information regarding the sale of Gulf Power.

Southern Power

On January 29, 2019, Pacific Gas & Electric Company (PG&E) filed petitions to reorganize under Chapter 11 of the U.S. Bankruptcy Code. Southern Power, together with its noncontrolling partners, owns four solar facilities where PG&E is the energy off-taker for approximately 207 MWs of capacity under long-term PPAs. PG&E is also the transmission provider for these facilities and two of Southern Power's other solar facilities. Southern Power has evaluated the recoverability of its investments in these solar facilities under various scenarios, including selling the related energy into the competitive markets, and has concluded they are not impaired. At December 31, 2018, Southern Power had outstanding accounts receivables due from PG&E of $1 million related to the PPAs and $36 million related to the transmission interconnections. Southern Company does not expect a material impact to its financial statements if, as a result of the bankruptcy proceedings, PG&E does not perform in accordance with the PPAs or the terms of the PPAs are renegotiated; however, the ultimate outcome of this matter cannot be determined at this time.

Southern Company Gas

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, 2018, the facility's property, plant, and equipment had a net book value of $109 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, 2018. 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 Notes 1, 5, and 6 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 85% of Southern Company's total operating revenues for 2018, 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 Southern 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 Southern Company's results of operations and financial condition than they would on a non-regulated company. See Note 15 to the financial statements for information regarding the sale of Gulf Power and three of Southern Company Gas' natural gas distribution utilities.

As reflected in Note 2 to the financial statements under "Southern Company – Regulatory Assets and Liabilities," 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 Southern Company's financial statements.

Estimated Cost, Schedule, and Rate Recovery for the Construction of Plant Vogtle Units 3 and 4

In 2016, the Georgia PSC approved the Vogtle Cost Settlement Agreement, which resolved certain prudency matters in connection with Georgia Power's fifteenth VCM report. In December 2017, the Georgia PSC approved Georgia Power's seventeenth VCM report, 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, as well as a modification of the Vogtle Cost Settlement Agreement. The Georgia PSC's related order stated that under the modified Vogtle Cost Settlement Agreement, (i) none of the $3.3 billion of costs incurred through December 31, 2015 should be disallowed as imprudent; (ii) capital costs incurred up to $5.68 billion would be presumed to be reasonable and prudent with the burden of proof on any party challenging such costs; (iii) Georgia Power would have the burden of proof to show that any capital costs above $5.68 billion were prudent; (iv) Georgia Power's total project capital cost forecast of $7.3 billion (net of $1.7 billion received under the Guarantee Settlement Agreement and approximately $188 million in related Customer Refunds) was found reasonable and did not represent a cost cap; and (v) prudence decisions would be made subsequent to achieving fuel load for Unit 4.

In its order, the Georgia PSC also stated if other conditions change and assumptions upon which Georgia Power's seventeenth VCM report are based do not materialize, the Georgia PSC reserved the right to reconsider the decision to continue construction.

In the second quarter 2018, Georgia Power revised its base cost forecast and estimated contingency to complete construction and start-up of Plant Vogtle Units 3 and 4 to $8.0 billion and $0.4 billion, respectively, for a total project capital cost forecast of $8.4 billion (net of $1.7 billion received under the Guarantee Settlement Agreement and approximately $188 million in related Customer Refunds). Although Georgia Power believes these incremental costs are reasonable and necessary to complete the project and the Georgia PSC's order in the seventeenth VCM proceeding specifically states that the construction of Plant Vogtle Units 3 and 4 is not subject to a cost cap, Georgia Power did not seek rate recovery for the $0.7 billion increase in costs included in the current base capital cost forecast in the nineteenth VCM report. In connection with future VCM filings, Georgia Power may request the Georgia PSC to evaluate costs currently included in the construction contingency estimate for rate recovery as and when they are appropriately included in the base capital cost forecast. After considering the significant level of uncertainty that exists regarding the future recoverability of costs included in the construction contingency estimate since the ultimate outcome of these matters is subject to the outcome of future assessments by management, as well as Georgia PSC decisions in these future

regulatory proceedings, Georgia Power recorded a total pre-tax charge to income of $1.1 billion ($0.8 billion after tax) in the second quarter 2018.

Georgia Power's revised cost estimate reflects an expected in-service date of November 2021 for Unit 3 and November 2022 for Unit 4.

As construction continues, challenges with management of contractors, subcontractors, and vendors; labor productivity, availability, and/or cost escalation; procurement, fabrication, delivery, assembly, and/or installation and testing, including any required engineering changes, of plant systems, structures, and components (some of which are based on new technology that only recently began initial operation in the global nuclear industry at this scale); or other issues could arise and change the projected schedule and estimated cost. Monthly construction production targets required to maintain the current project schedule will continue to increase significantly throughout 2019. To meet these increasing monthly targets, existing craft construction productivity must improve and additional craft laborers must be retained and deployed.

Georgia Power and Southern Nuclear believe it is a leading practice in connection with a construction project of this size and complexity to periodically validate recent construction progress in comparison to the projected schedule and to verify and update quantities of commodities remaining to install, labor productivity, and forecasted staffing needs. This verification process, led by Southern Nuclear, was underway as of December 31, 2018 and is expected to be completed during the second quarter 2019. Georgia Power currently does not anticipate any material changes to the total estimated project capital cost forecast for Plant Vogtle Units 3 and 4 or the expected in-service dates of November 2021 and November 2022, respectively, resulting from this verification process. However, the ultimate impact on cost and schedule, if any, will not be known until the verification process is completed. Georgia Power is required to report the results and any project impacts to the Georgia PSC by May 15, 2019.

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 ITAAC 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. Any extension of the in-service dates of November 2021 for Unit 3 and November 2022 for Unit 4 is currently estimated to result in additional base capital costs of approximately $50 million per month, based on Georgia Power's ownership interests, and AFUDC of approximately $12 million per month. While Georgia Power is not precluded from seeking recovery of any future capital cost forecast increase, management will ultimately determine whether or not to seek recovery. Any further changes to the capital cost forecast that are not expected to be recoverable through regulated rates will be required to be charged to income and such charges could be material.

Given the significant complexity involved in estimating the future costs to complete construction and start-up of Plant Vogtle Units 3 and 4 and the significant management judgment necessary to assess the related uncertainties surrounding future rate recovery of any projected cost increases, as well as the potential impact on Southern Company's results of operations and cash flows, Southern Company considers these items to be critical accounting estimates. See Note 2 to the financial statements under "Georgia Power – Nuclear Construction" 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

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 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 federal and state deferred income tax liabilities and assets to be critical accounting estimates.

Asset Retirement Obligations

AROs are computed as the fair value of the estimated costs for an asset's future retirement and are recorded in the period in which the liability is incurred. The estimated 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 and the related state rules, 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 AROs 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 traditional electric operating companies and Southern Company Gas also have identified retirement obligations, such as obligations related to certain electric transmission and distribution facilities, certain asbestos containing material within long-term assets not subject to ongoing repair and maintenance activities, certain wireless communication towers, the disposal of polychlorinated biphenyls in certain transformers, leasehold improvements, equipment on customer property, and property associated with the Southern Company system's rail lines and natural gas pipelines. 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 retirement obligations will be recognized when sufficient information becomes available to support a reasonable estimation of the retirement obligation.

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. During 2018, Alabama Power and Georgia Power recorded increases of approximately $1.2 billion and $3.1 billion, respectively, to their AROs related to the disposal of CCR and increases of approximately $300 million and $130 million, respectively, to their AROs related to updated nuclear decommissioning cost site studies. Alabama Power's CCR-related update resulted from feasibility studies performed on ash ponds in use at the plants it operates, which indicated that additional closure costs, primarily related to increases in estimated ash volume, water management requirements, and design revisions, will be required to close these ash ponds under the planned closure-in-place methodology. Georgia Power's CCR-related update resulted from a strategic assessment which indicated additional closure costs will be required to close its ash ponds, primarily due to changes in closure strategies, the estimated amount of ash to be excavated, and additional water management requirements necessary to support closure strategies. The traditional electric operating companies expect to periodically update their ARO cost estimates. See FUTURE EARNINGS POTENTIAL – "Environmental Matters – Environmental Laws and Regulations – Coal Combustion Residuals" herein and Note 6 to the financial statements 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 Southern Company believes that the assumptions used are appropriate, differences in actual experience or significant changes in assumptions would affect its pension and other postretirement benefit 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.

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

Change in Assumption	Increase/(Decrease) in Total Benefit Expense for 2019	Increase/(Decrease) in Projected Obligation for Pension Plan at December 31, 2018	Increase/(Decrease) in Projected Obligation for Other Postretirement Benefit Plans at December 31, 2018
		(in millions)	
25 basis point change in discount rate	$37/$(36)	$434/$(411)	$50/$(48)
25 basis point change in salaries	$11/$(11)	$105/$(101)	$–/$–
25 basis point change in long-term return on plan assets	$33/$(33)	N/A	N/A

N/A – Not applicable

See Note 11 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 $5.3 billion at December 31, 2018. As a result of the Southern Company Gas Dispositions, goodwill was reduced by $910 million during 2018. In addition, Southern Company Gas recorded a $42 million goodwill impairment charge in 2018 in contemplation of the sale of Pivotal Home Solutions.

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 $613 million at December 31, 2018.

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 15 to the financial statements for additional

information related to Southern Company's 2016 acquisitions of Southern Company Gas and PowerSecure, as well as the Southern Company Gas 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 and Note 14 to the financial statements 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, and other risks. See FUTURE EARNINGS POTENTIAL herein and Notes 2 and 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. 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

See Note 1 to the financial statements under "Recently Adopted Accounting Standards" for additional information.

In 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 adopted the new standard effective January 1, 2019.

Southern Company elected the transition methodology provided by ASU No. 2018-11, *Leases (Topic 842): Targeted Improvements*, whereby the requirements of ASU 2016-02 are applied on a prospective basis as of the adoption date of January 1, 2019, without restating prior periods. Southern Company elected the package of practical expedients provided by ASU 2016-02

that allows prior determinations of whether existing contracts are, or contain, leases and the classification of existing leases to continue without reassessment. Additionally, Southern Company applied the use-of-hindsight practical expedient in determining lease terms as of the date of adoption and elected the practical expedient that allows existing land easements not previously accounted for as leases not to be reassessed. Southern Company also made accounting policy elections to account for short-term leases in all asset classes as off-balance sheet leases and combined lease and non-lease components in the computations of lease obligations and right-of-use assets for most asset classes.

The Southern Company system completed the implementation of a new application to track and account for its leases and updated its internal controls and accounting policies to support the accounting for leases under ASU 2016-02. The Southern Company system completed its lease inventory and determined its most significant leases involve PPAs, real estate, and communication towers where certain of Southern Company's subsidiaries are the lessee and PPAs where certain of Southern Company's subsidiaries are the lessor. In the first quarter 2019, the adoption of ASU 2016-02 resulted in recording lease liabilities and right-of-use assets on Southern Company's balance sheet each totaling approximately $2.0 billion, with no impact on Southern Company's statement of income.

FINANCIAL CONDITION AND LIQUIDITY

Overview

Earnings in all periods presented were negatively affected by charges associated with plants under construction; however, Southern Company's financial condition remained stable at December 31, 2018.

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 and closures of ash ponds, 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 2019 through 2021, 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 decreased in value at December 31, 2018 as compared to December 31, 2017. No contributions to the qualified pension plan were made for the year ended December 31, 2018 and no mandatory contributions to the qualified pension plans are anticipated during 2019. See "Contractual Obligations" herein and Notes 6 and 11 to the financial statements under "Nuclear Decommissioning" and "Pension Plans," respectively, for additional information.

Net cash provided from operating activities in 2018 totaled $6.9 billion, an increase of $0.6 billion from 2017. The increase in net cash provided from operating activities was primarily due to the timing of vendor payments and increased fuel cost recovery. Net cash provided from operating activities in 2017 totaled $6.4 billion, an increase of $1.5 billion from 2016. Significant changes in operating cash flow for 2017 as compared to 2016 included 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 used for investing activities in 2018, 2017, and 2016 totaled $5.8 billion, $7.2 billion, and $20.0 billion, respectively. The cash used for investing activities in 2018 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 and capital expenditures for Southern Company Gas' infrastructure replacement programs, partially offset by proceeds from the sale transactions described in Note 15 to the financial statements. 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.

Net cash used for financing activities totaled $1.8 billion in 2018 primarily due to net redemptions and repurchases of long-term debt, common stock dividend payments, and a decrease in commercial paper borrowings, partially offset by net issuances of short-term bank debt, proceeds from Southern Power's sales of non-controlling equity interests in entities indirectly owning substantially all of its solar facilities and eight of its wind facilities, and the issuance of common stock. 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. 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 2018 included the reclassification of $5.7 billion and $3.3 billion in total assets and liabilities held for sale, respectively, primarily associated with Gulf Power, as well as decreases of $3.0 billion and $0.4 billion in total assets and liabilities, respectively, associated with the sales described in Note 15 to the financial statements under "Southern Power" and "Southern Company Gas." Also see Note 15 to the financial statements under "Southern Company's Sale of Gulf Power" and "Assets Held for Sale" for additional information. After adjusting for these changes, other significant balance sheet changes included an increase of $7.1 billion in total property, plant, and equipment primarily related to the $4.7 billion increase in AROs at Alabama Power and Georgia Power, as well as the traditional electric operating companies' installation of equipment to comply with environmental standards and construction of electric generation, transmission, and distribution facilities and Southern Company Gas' capital expenditures for infrastructure replacement programs, partially offset by the second quarter 2018 charge related to the construction of Plant Vogtle Units 3 and 4; a decrease of $3.1 billion in long-term debt (including amounts due within one year) resulting from the repayment of long-term debt; an increase of $3.0 billion in noncontrolling interests at Southern Power as a result of sales of interests in entities indirectly owning substantially all of its solar facilities and eight of its wind facilities; and an increase of $1.9 billion in other regulatory assets, deferred primarily related to AROs at Georgia Power. See Notes 2 and 15 to the financial statements under "Georgia Power – Nuclear Construction" and "Southern Power – Sales of Renewable Facility Interests," respectively, as well as Notes 6 and 8 to the financial statements and "Financing Activities" herein for additional information.

At the end of 2018, the market price of Southern Company's common stock was $43.92 per share (based on the closing price as reported on the NYSE) and the book value was $23.91 per share, representing a market-to-book value ratio of 184%, compared to $48.09, $23.99, and 201%, respectively, at the end of 2017.

Southern Company's consolidated ratio of common equity to total capitalization plus short-term debt was 32.5% and 31.5% at December 31, 2018 and 2017, respectively. See Note 8 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 Southern Company's stock plans, private placements, or public offerings. The amount and timing of additional equity and debt issuances in 2019, 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 its pending sale of Plant Mankato. However, the amount, type, and timing of any future financings, if needed, will depend upon prevailing market conditions, regulatory approval, and other factors. See Note 15 to the financial statements under "Southern Power – Sales of Natural Gas Plants" 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. At December 31, 2018, Georgia Power had borrowed $2.6 billion under

the FFB Credit Facility. In July 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.

In September 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 March 31, 2019, 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 8 to the financial statements under "Long-term Debt – DOE Loan Guarantee Borrowings" for additional information regarding the Loan Guarantee Agreement, including applicable covenants, events of default, mandatory prepayment events (including any decision not to continue construction of Plant Vogtle Units 3 and 4), and additional conditions to borrowing. Also see Note 2 to the financial statements under "Georgia Power – 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 8 to the financial statements under "Bank Credit Arrangements" for additional information.

At December 31, 2018, Southern Company's current liabilities exceeded current assets by $4.7 billion, primarily due to $3.2 billion of long-term debt that is due within one year (including approximately $1.3 billion at the parent company, $0.2 billion at Alabama Power, $0.6 billion at Georgia Power, $0.6 billion at Southern Power, and $0.4 billion at Southern Company Gas) and $2.9 billion of notes payable (including approximately $1.8 billion at the parent company, $0.3 billion at Georgia Power, $0.1 billion at Southern Power, and $0.7 billion at Southern Company Gas). Subsequent to December 31, 2018, using proceeds from the sale of Gulf Power, the Southern Company parent entity repaid $0.7 billion of its long-term debt due within one year and all $1.8 billion of its notes payable at December 31, 2018. See "Financing Activities" herein for additional information. 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, 2018, Southern Company and its subsidiaries had approximately $1.4 billion of cash and cash equivalents. Committed credit arrangements with banks at December 31, 2018 were as follows:

Company	Expires 2019	Expires 2020	Expires 2022	Total	Unused[d]	Executable Term Loans: One Year	Executable Term Loans: Two Years	Expires Within One Year: Term Out	Expires Within One Year: No Term Out
					(in millions)				
Southern Company[a]	$ —	$ —	$2,000	$ 2,000	$ 1,999	$ —	$ —	$ —	$ —
Alabama Power	33	500	800	1,333	1,333	—	—	—	33
Georgia Power	—	—	1,750	1,750	1,736	—	—	—	—
Mississippi Power	100	—	—	100	100	—	—	—	100
Southern Power[b]	—	—	750	750	727	—	—	—	—
Southern Company Gas[c]	—	—	1,900	1,900	1,895	—	—	—	—
Other	30	—	—	30	30	—	—	—	30
Southern Company Consolidated[e]	$ 163	$ 500	$7,200	$ 7,863	$ 7,820	$ —	$ —	$ —	$ 163

(a) Represents the Southern Company parent entity.

(b) Does not include Southern Power Company's $120 million continuing letter of credit facility for standby letters of credit expiring in 2021, of which $17 million was unused at December 31, 2018. Southern Power's subsidiaries are not parties to its bank credit arrangement.

(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 this arrangement. Southern Company Gas' committed credit arrangement also includes $500 million for which Nicor Gas is the borrower and which is restricted for working capital needs of Nicor Gas. Pursuant to this multi-year credit arrangement, the allocations between Southern Company Gas Capital and Nicor Gas may be adjusted.

(d) Amounts used are for letters of credit.

(e) Excludes $280 million of committed credit arrangements of Gulf Power, which was sold on January 1, 2019. See Note 15 to the financial statements under "Southern Company's Sale of Gulf Power" for additional information.

See Note 8 to the financial statements under "Bank Credit Arrangements" for additional information.

Most of these bank credit arrangements, as well as the term loan arrangements of Alabama 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, 2018, 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 at December 31, 2018 was approximately $1.6 billion, which included $82 million related to Gulf Power. In addition, at December 31, 2018, the traditional electric operating companies had approximately $403 million of revenue bonds outstanding that are required to be remarketed within the next 12 months, which included $58 million related to Gulf Power. See Note 15 to the financial statements under "Southern Company's Sale of Gulf Power" for information regarding the sale of Gulf Power on January 1, 2019. Subsequent to December 31, 2018, Georgia Power redeemed approximately $108 million of obligations related to outstanding variable rate pollution control revenue bonds.

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

Details of short-term borrowings were as follows:

	Short-term Debt at the End of the Period		Short-term Debt During the Period (*)		
	Amount Outstanding	Weighted Average Interest Rate	Average Amount Outstanding	Weighted Average Interest Rate	Maximum Amount Outstanding
	(in millions)		*(in millions)*		*(in millions)*
December 31, 2018:					
Commercial paper	**$ 1,064**	**3.0%**	**$ 1,655**	**2.3%**	**$ 3,042**
Short-term bank debt	**1,851**	**3.1%**	**1,722**	**2.9%**	**2,504**
Total	**$ 2,915**	**3.1%**	**$ 3,377**	**2.6%**	
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 %	

(*) Average and maximum amounts are based upon daily balances during the 12-month periods ended December 31, 2018, 2017, and 2016.

In addition to the short-term borrowings of Southern Power Company included in the table above, at December 31, 2016, Southern Power Company subsidiaries assumed credit agreements (Project Credit Facilities) 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.

Southern 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 2018, Southern Company issued approximately 11.6 million shares of common stock primarily through employee equity compensation plans and received proceeds of approximately $442 million.

In addition, during the third and fourth quarters 2018, Southern Company issued a total of approximately 12.1 million and 2.5 million shares, respectively, 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 $540 million and $108 million, respectively, net of $5 million and $1 million in commissions, respectively.

The following table outlines the long-term debt financing activities for Southern Company and its subsidiaries for the year ended December 31, 2018:

Company	Senior Note Issuances	Senior Note Maturities, Redemptions, and Repurchases	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]	$ 750	$ 1,000	$ —	$ —	$ —	$ —
Alabama Power	500	—	120	120	—	1
Georgia Power	—	1,500	108	469	—	111
Mississippi Power	600	155	—	43	—	900
Southern Power	—	350	—	—	—	420
Southern Company Gas	—	155	—	200	300	—
Other[c]	—	100	—	—	100	13
Elimination[d]	—	—	—	—	—	(4)
Southern Company Consolidated	$ 1,850	$ 3,260	$ 228	$ 832	$ 400	$ 1,441

(a) Includes reductions in capital lease obligations resulting from cash payments under capital leases.

(b) Represents the Southern Company parent entity.

(c) In November 2018, SEGCO, as borrower, and Alabama Power, as guarantor, entered into a $100 million long-term delayed draw floating rate bank term loan bearing interest based on three-month LIBOR, which SEGCO used to repay at maturity $100 million aggregate principal amount of Series 2013A Senior Notes due December 1, 2018. See Note 9 to the financial statements under "Guarantees" for additional information.

(d) Represents reductions in affiliate capital lease obligations at Georgia Power, which 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. The subsidiaries also used the proceeds for their construction programs.

In March 2018, Southern Company entered into a $900 million short-term floating rate bank loan bearing interest based on one-month LIBOR, which was repaid in August 2018.

In April 2018, Southern Company borrowed $250 million pursuant to a short-term uncommitted bank credit arrangement, bearing interest at a rate agreed upon by Southern Company and the bank from time to time and payable on no less than 30 days' demand by the bank. Subsequent to December 31, 2018, Southern Company repaid this loan.

In June 2018, Southern Company repaid at maturity two $100 million short-term floating rate bank term loans.

In August 2018, Southern Company issued $750 million aggregate principal amount of Series 2018A Floating Rate Senior Notes due February 14, 2020 bearing interest based on three-month LIBOR, entered into a $1.5 billion short-term floating rate bank loan bearing interest based on one-month LIBOR, and repaid $250 million borrowed in August 2017 pursuant to a short-term uncommitted bank credit arrangement. Subsequent to December 31, 2018, Southern Company repaid the $1.5 billion short-term floating rate bank loan.

In the third quarter 2018, Southern Company repaid at maturity $500 million aggregate principal amount of 1.55% Senior Notes and $500 million aggregate principal amount of Series 2013A 2.45% Senior Notes.

Subsequent to December 31, 2018, through cash tender offers, Southern Company repurchased and retired approximately $522 million of the $1.0 billion aggregate principal amount outstanding of its 1.85% Senior Notes due July 1, 2019 (1.85% Notes), approximately $180 million of the $350 million aggregate principal amount outstanding of its Series 2014B 2.15% Senior Notes due September 1, 2019 (Series 2014B Notes), and approximately $504 million of the $750 million aggregate principal amount outstanding of its Series 2018A Floating Rate Notes due February 14, 2020 (Series 2018A Notes), for an aggregate purchase price, excluding accrued and unpaid interest, of approximately $1.2 billion. In addition, subsequent to December 31, 2018, and following the completion of the cash tender offers, Southern Company completed the redemption of all of the Series 2018A Notes remaining outstanding and called for redemption all of the 1.85% Notes and Series 2014B Notes remaining outstanding.

Subsequent to December 31, 2018, Alabama Power repaid at maturity $200 million aggregate principal amount of Series Z 5.125% Senior Notes.

In January 2018, Georgia Power repaid its outstanding $150 million short-term floating rate bank loan due May 31, 2018.

In May 2018, through cash tender offers, Georgia Power repurchased and retired $89 million of the $250 million aggregate principal amount outstanding of its Series 2007A 5.65% Senior Notes due March 1, 2037, $326 million of the $500 million aggregate principal amount outstanding of its Series 2009A 5.95% Senior Notes due February 1, 2039, and $335 million of the $600 million aggregate principal amount outstanding of its Series 2010B 5.40% Senior Notes due June 1, 2040, for an aggregate purchase price, excluding accrued and unpaid interest, of $902 million.

Subsequent to December 31, 2018, Georgia Power redeemed approximately $13 million, $20 million, and $75 million aggregate principal amount of Development Authority of Burke County (Georgia) Pollution Control Revenue Bonds (Georgia Power Company Plant Vogtle Project), First Series 1992, Eighth Series 1994, and Second Series 1995, respectively.

In March 2018, Mississippi Power entered into a $300 million short-term floating rate bank loan bearing interest based on one-month LIBOR, of which $200 million was repaid in the second quarter 2018 and $100 million was repaid in the third quarter 2018. The proceeds of this loan, together with the proceeds of Mississippi Power's $600 million senior notes issuances, were used to repay Mississippi Power's $900 million unsecured floating rate term loan.

In October 2018, Mississippi Power completed the redemption of all 334,210 outstanding shares of its preferred stock (as well as related depositary shares), with an aggregate par value of approximately $33.4 million.

In May 2018, Southern Power entered into two short-term floating rate bank loans, each for an aggregate principal amount of $100 million, which bear interest based on one-month LIBOR. In November 2018, Southern Power repaid one of these short-term loans.

During 2018, Southern Power received approximately $148 million of third-party tax equity related to certain of its renewable facilities. See Note 15 to the financial statements under "Southern Power" for additional information.

Prior to its sale, in the second quarter 2018, Pivotal Utility Holdings caused $200 million aggregate principal amount of gas facility revenue bonds to be redeemed.

In May 2018, Southern Company Gas Capital borrowed $95 million pursuant to a short-term uncommitted bank credit arrangement, guaranteed by Southern Company Gas, bearing interest at a rate agreed upon by Southern Company Gas Capital and the bank from time to time and payable on no less than 30 days' demand by the bank. In July 2018, Southern Company Gas Capital repaid this loan.

Other long-term debt issuances for Southern Company Gas include the issuance by Nicor Gas of $300 million aggregate principal amount of first mortgage bonds in a private placement, of which $100 million was issued in August 2018 and $200 million was issued in November 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, 2018, 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, 2018 were as follows:

Credit Ratings	Maximum Potential Collateral Requirements[a]
	(in millions)
At BBB and/or Baa2	$ 30
At BBB- and/or Baa3	$ 542
At BB+ and/or Ba1[b]	$ 2,176

(a) Includes potential collateral requirements related to Gulf Power of $111 million and $221 million at a credit rating of BBB- and/or Baa3 and BB+ and/or Ba1, respectively. See Note 15 to the financial statements under "Southern Company's Sale of Gulf Power" for information regarding the sale of Gulf Power on January 1, 2019.

(b) 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 February 26, 2018, Moody's revised its rating outlook for Mississippi Power from stable to positive. On August 8, 2018, Moody's upgraded Mississippi Power's senior unsecured rating to Baa3 from Ba1 and maintained the positive rating outlook.

On February 28, 2018, Fitch removed Mississippi Power from rating watch negative and revised its rating outlook from stable to positive.

Also on February 28, 2018, Fitch downgraded the senior unsecured long-term debt rating of Southern Company to BBB+ from A- with a stable outlook and of Georgia Power to A from A+ with a negative outlook. On August 9, 2018, Fitch downgraded the senior unsecured long-term debt rating of Georgia Power to A- from A.

On March 14, 2018, S&P upgraded the senior unsecured long-term debt rating of Mississippi Power to A- from BBB+. The outlook remained negative.

On August 8, 2018, Moody's downgraded the senior unsecured debt rating of Georgia Power to Baa1 from A3.

On September 28, 2018, Moody's revised its rating outlooks for Southern Company, Alabama Power, and Georgia Power from negative to stable.

Also on September 28, 2018, Fitch assigned a negative rating outlook to the ratings of Southern Company and its subsidiaries (excluding Mississippi Power).

As a result of 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. Southern Company and most of its regulated subsidiaries have taken actions to mitigate the resulting impacts, which, among other alternatives, include adjusting capital structure. Absent actions by Southern Company and its subsidiaries that fully mitigate the impacts, the credit ratings of Southern Company and certain of its subsidiaries could be negatively affected. See Note 2 to the financial statements for additional information related to state PSC or other regulatory agency actions related to the Tax Reform Legislation, including approvals of capital structure adjustments for Alabama Power, Georgia Power, and Atlanta Gas Light by their respective state PSCs, which are expected to help mitigate the potential adverse impacts to certain of their credit metrics.

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, 2018 have a notional amount of $2.0 billion and are intended to mitigate interest rate volatility related to existing fixed rate obligations. The weighted average interest rate on $5.8 billion of long-term variable interest rate exposure at December 31, 2018 was 3.02%. 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 $58 million at December 31, 2018. See Note 1 to the financial statements under "Financial Instruments" and Note 14 to the financial statements for additional information.

Southern Power Company had foreign currency denominated debt of €1.1 billion at December 31, 2018. 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, 2018 when compared to the year ended December 31, 2017.

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:

	2018	2017
	(in millions)	
Contracts outstanding at the beginning of the period, assets (liabilities), net	**$ (163)**	$ 41
Contracts realized or settled	**93**	(8)
Current period changes[(a)]	**(131)**	(196)
Contracts outstanding at the end of the period, assets (liabilities), net[(b)(c)]	**$ (201)**	$ (163)

(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 $8 million and $11 million at December 31, 2018 and 2017, respectively.

(c) Includes $6 million of net liabilities related to Gulf Power. See Note 15 to the financial statements under "Southern Company's Sale of Gulf Power" for information regarding the sale of Gulf Power on January 1, 2019.

The net hedge volumes of energy-related derivative contracts were 431 million mmBtu and 621 million mmBtu at December 31, 2018 and 2017, respectively.

For the traditional electric operating companies and Southern Power, the weighted average swap contract cost above market prices was approximately $0.12 per mmBtu at December 31, 2018 and $0.15 per mmBtu at December 31, 2017. 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, 2018 and 2017, a portion 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. See Note 14 to the financial statements for additional information.

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 13 to the financial statements for further discussion of fair value measurements. The maturities of the energy-related derivative contracts at December 31, 2018 were as follows:

	Fair Value Measurements December 31, 2018			
	Total Fair Value	Maturity		
		Year 1	Years 2&3	Years 4&5
		(in millions)		
Level 1	$ (179)	$ (59)	$ (86)	$ (34)
Level 2	(22)	20	(17)	(25)
Level 3	—	—	—	—
Fair value of contracts outstanding at end of period	$ (201)	$ (39)	$ (103)	$ (59)

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 14 to the financial statements.

With the exception of Southern Company Gas' subsidiary, Atlanta Gas Light, and the Southern Company Gas wholesale gas services business, the Southern Company system is not exposed to concentrations of credit risk. Concentration of credit risk occurs at Atlanta Gas Light for amounts billed for services and other costs to its customers, which consist of 15 Marketers in Georgia responsible for the retail sale of natural gas to end-use customers in Georgia. For 2018, the four largest Marketers based on customer count, which includes SouthStar, accounted for 20% 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, 2018, Southern Company Gas' wholesale gas services business' top 20 counterparties represented approximately 48%, or $298 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 Southern 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 $8.0 billion for 2019, $7.7 billion for 2020, $6.7 billion for 2021, $6.3 billion for 2022, and $6.0 billion for 2023. These amounts include expenditures of approximately $1.5 billion, $1.2 billion, $1.0 billion, and $0.5 billion for the construction of Plant Vogtle Units 3 and 4 in 2019, 2020, 2021, and 2022, respectively. These amounts do not include up to approximately $0.5 billion per year on average for 2019 through 2023 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 $0.5 billion, $0.2 billion, $0.3 billion, $0.3 billion, and $0.2 billion for 2019, 2020, 2021, 2022, and 2023, respectively. These estimated expenditures do not include any potential compliance costs associated with pending 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 Southern Company's ARO liabilities. These costs, which are expected to change and could change materially as underlying assumptions are refined and the cost and the method and timing of compliance activities continue to be evaluated, are currently estimated to be approximately $0.5 billion, $0.5 billion, $0.7 billion, $0.9 billion, and $0.9 billion for 2019, 2020, 2021, 2022, and 2023, respectively. See FUTURE EARNINGS POTENTIAL – "Environmental

Matters – Environmental Laws and Regulations – Coal Combustion Residuals" herein and Note 6 to the financial statements 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 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 15 to the financial statements under "Southern Power" for additional information regarding Southern Power's plant acquisitions.

The construction program also includes Plant Vogtle Units 3 and 4, which includes components based on new technology that only recently began initial operation in the global nuclear industry at this scale and which may be subject to additional revised cost estimates during construction. The ability to control costs and avoid cost and schedule 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, availability, and productivity; challenges with management of contractors, subcontractors, or vendors; adverse weather conditions; shortages, increased costs, or 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; engineering or design problems; design and other licensing-based compliance matters, including the timely resolution of ITAAC and the related approvals by the NRC; challenges with start-up activities, including major equipment failure and system integration; and/or operational performance. See Note 2 to the financial statements under "Georgia Power – Nuclear Construction" for information regarding Plant Vogtle Units 3 and 4 and 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 6 to the financial statements under "Nuclear Decommissioning."

In addition, as discussed in Note 11 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.

Funding requirements related to obligations associated with scheduled maturities of long-term debt, as well as the related interest, derivative obligations, preferred stock dividends of subsidiaries, leases, pipeline charges, storage capacity, gas supply, asset management agreements, other purchase commitments, ARO settlements, and trusts are detailed in the contractual obligations table that follows. See Notes 1, 6, 8, 9, 11, and 14 to the financial statements for additional information.

Contractual Obligations

The Southern Company system's contractual obligations at December 31, 2018 (excluding Gulf Power) were as follows:

	2019	2020-2021	2022-2023	After 2023	Total
			(in millions)		
Long-term debt[a] —					
Principal	$ 3,133	$ 7,204	$ 4,354	$ 28,950	$ 43,641
Interest	1,668	3,082	2,270	25,796	32,816
Preferred stock dividends of subsidiaries[b]	15	29	29	—	73
Financial derivative obligations[c]	610	243	109	—	962
Operating leases[d]	156	244	177	1,040	1,617
Capital leases[d]	25	22	8	143	198
Pipeline charges, storage capacity, and gas supply[e]	781	1,104	901	1,871	4,657
Asset management agreements[f]	10	8	—	—	18
Purchase commitments —					
Capital[g]	7,600	13,608	11,486	—	32,694
Fuel[h]	3,168	3,854	1,863	5,862	14,747
Purchased power[i]	304	653	545	2,494	3,996
Other[j]	328	642	464	2,265	3,699
ARO settlements[k]	451	1,186	1,841	—	3,478
Trusts —					
Nuclear decommissioning[l]	5	11	11	88	115
Pension and other postretirement benefit plans[m]	137	265	—	—	402
Total	$ 18,391	$ 32,155	$ 24,058	$ 68,509	$ 143,113

(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 8 to the financial statements under "Long-term Debt – 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 at December 31, 2018, 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 Alabama Power. Preferred stock does not mature; therefore, amounts are provided for the next five years only.

(c) See Notes 1 and 14 to the financial statements.

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

(e) 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 47 million mmBtu at floating gas prices calculated using forward natural gas prices at December 31, 2018 and valued at $150 million. Southern Company Gas provides guarantees to certain gas suppliers for certain of its subsidiaries in support of payment obligations.

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

(g) 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, capital expenditures covered under LTSAs, and estimated capital expenditures for AROs, which are reflected in "Fuel," "Other," and "ARO settlements," respectively. These amounts also exclude up to approximately $0.5 billion per year on average for 2019 through 2023 for Southern Power's planned expenditures for plant acquisitions and placeholder growth. At December 31, 2018, significant purchase commitments were outstanding in connection with the construction program. See FUTURE EARNINGS POTENTIAL – "Environmental Matters – Environmental Laws and Regulations" and "Construction Programs" herein for additional information.

(h) 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 NYMEX future prices at December 31, 2018.

(i) Estimated minimum long-term obligations for various PPA purchases from gas-fired, biomass, and wind-powered facilities and capacity payments related to Plant Vogtle Units 1 and 2. See Note 9 to the financial statements under "Fuel and Power Purchase Agreements" for additional information.

(j) 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.

(k) Represents estimated costs for a five-year period associated with closing and monitoring ash ponds in accordance with the CCR Rule and the related state rules, which are reflected in Southern Company's ARO liabilities. Material expenditures in future years for ARO settlements also will be required for ash ponds, nuclear decommissioning, and other liabilities reflected in Southern Company's AROs. See FUTURE EARNINGS POTENTIAL – "Environmental Matters – Environmental Laws and Regulations – Coal Combustion Residuals" herein and Note 6 to the financial statements for additional information.

(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 6 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 11 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.

OVERVIEW

Business Activities

Alabama Power 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 Alabama Power'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, including CCR rules, reliability, fuel, capital expenditures, including improving the electric transmission and distribution systems, and restoration following major storms. Alabama Power 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 Alabama Power for the foreseeable future. On May 1, 2018, the Alabama PSC approved modifications to Rate RSE and other commitments designed to position Alabama Power to address the retail rate impact and the growing pressure on its credit quality resulting from the Tax Reform Legislation. See FUTURE EARNINGS POTENTIAL – "Retail Regulatory Matters" and FINANCIAL CONDITION AND LIQUIDITY – "Credit Rating Risk" herein for additional information.

Alabama Power 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 stock. Alabama Power'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 Alabama Power's results and generally targets the top quartile of these surveys in measuring performance.

See RESULTS OF OPERATIONS herein for information on Alabama Power's financial performance.

Earnings

Alabama Power's 2018 net income after dividends on preferred and preference stock was $930 million, representing an $82 million, or 9.7%, increase over the previous year. The increase was primarily due to a decrease in income tax expense, partially offset by a decrease in retail revenues associated with customer bill credits related to the Tax Reform Legislation. The increase also reflects an increase in revenues associated with colder weather in the first quarter 2018 and warmer weather in the second and third quarters 2018 compared to the corresponding periods in 2017, partially offset by an accrual for a Rate RSE refund. See FUTURE EARNINGS POTENTIAL – "Retail Regulatory Matters – Rate RSE" herein for additional information.

Alabama Power'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.

MANAGEMENT'S DISCUSSION AND ANALYSIS (continued)
Alabama Power Company 2018 Annual Report

RESULTS OF OPERATIONS

A condensed income statement for Alabama Power follows:

	Amount	Increase (Decrease) from Prior Year	
	2018	**2018**	2017
		(in millions)	
Operating revenues	**$ 6,032**	**$ (7)**	$ 150
Fuel	**1,301**	**76**	(72)
Purchased power	**432**	**104**	(6)
Other operations and maintenance	**1,669**	**(40)**	152
Depreciation and amortization	**764**	**28**	33
Taxes other than income taxes	**389**	**5**	4
Total operating expenses	**4,555**	**173**	111
Operating income	**1,477**	**(180)**	39
Allowance for equity funds used during construction	**62**	**23**	11
Interest expense, net of amounts capitalized	**323**	**18**	3
Other income (expense), net	**20**	**(23)**	17
Income taxes	**291**	**(277)**	37
Net income	**945**	**79**	27
Dividends on preferred and preference stock	**15**	**(3)**	1
Net income after dividends on preferred and preference stock	**$ 930**	**$ 82**	$ 26

Operating Revenues

Operating revenues for 2018 were $6.0 billion, reflecting a $7 million decrease from 2017. Details of operating revenues were as follows:

	2018	2017
	(in millions)	
Retail — prior year	**$ 5,458**	$ 5,322
Estimated change resulting from —		
Rates and pricing	**(354)**	362
Sales decline	**(10)**	(44)
Weather	**137**	(89)
Fuel and other cost recovery	**136**	(93)
Retail — current year	**5,367**	5,458
Wholesale revenues —		
Non-affiliates	**279**	276
Affiliates	**119**	97
Total wholesale revenues	**398**	373
Other operating revenues	**267**	208
Total operating revenues	**$ 6,032**	$ 6,039
Percent change	**(0.1)%**	2.6%

Retail revenues in 2018 were $5.4 billion. These revenues decreased $91 million, or 1.7%, in 2018 as compared to the prior year. The decrease in 2018 was primarily due to customer bill credits related to the Tax Reform Legislation and an accrual for a Rate RSE refund, partially offset by an increase in fuel revenues and colder weather in the first quarter and warmer weather in the second and third quarters 2018 as compared to the corresponding periods in 2017.

Retail revenues in 2017 were $5.5 billion. These revenues increased $136 million, or 2.6%, in 2017 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 as compared to the corresponding periods in 2016.

See Note 2 to the financial statements under "Alabama Power – 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.

Electric rates include provisions to recognize the recovery of fuel costs, purchased power costs, PPAs certificated by the Alabama PSC, and costs associated with the natural disaster reserve. Under these provisions, fuel and other cost recovery revenues generally equal fuel and other cost recovery expenses and do not affect net income. See FUTURE EARNINGS POTENTIAL – "Retail Regulatory Matters – Rate ECR" herein for additional information.

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

	2018	2017	2016
		(in millions)	
Capacity and other	**$ 101**	$ 96	$ 93
Energy	**178**	180	190
Total non-affiliated	**$ 279**	$ 276	$ 283

Wholesale revenues from sales to non-affiliates will vary depending on fuel prices, the market prices of wholesale energy compared to the cost of Alabama Power'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 Alabama Power's variable cost to produce the energy.

In 2018, wholesale revenues from sales to non-affiliates increased $3 million, or 1.1%, as compared to the prior year. In 2017, wholesale revenues from sales to non-affiliates decreased $7 million, or 2.5%, as compared to the prior year.

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 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 Alabama Power's energy cost recovery clause.

In 2018, wholesale revenues from sales to affiliates increased $22 million, or 22.7%, as compared to the prior year. In 2018, the price of energy increased 12.3% as a result of higher natural gas prices and KWH sales increased 10.0% primarily due to an increase in hydro generation. 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 2018, other operating revenues increased $59 million, or 28.4%, as compared to the prior year primarily due to revenues related to unregulated sales of products and services that were reclassified as other revenues as a result of the adoption of ASC 606, *Revenue from Contracts with Customers* (ASC 606). In prior periods, these revenues were included in other income (expense), net. See Note 1 to the financial statements for additional information regarding Alabama Power's adoption of ASC 606. This increase was partially offset by decreases in open access transmission tariff revenues primarily due to a lower rate related to the Tax Reform Legislation.

Energy Sales

Changes in revenues are influenced heavily by the change in the volume of energy sold from year to year. KWH sales for 2018 and the percent change from the prior year were as follows:

	Total KWHs	Total KWH Percent Change		Weather-Adjusted Percent Change	
	2018	**2018**	2017	**2018**	2017
	(in billions)				
Residential	**18.6**	**8.2%**	(6.1)%	**(0.4)%**	(1.2)%
Commercial	**13.9**	**1.9**	(3.4)	**(1.0)**	(1.3)
Industrial	**23.0**	**1.4**	1.7	**1.4**	1.7
Other	**0.2**	**(5.7)**	(5.0)	**(5.7)**	(5.0)
Total retail	**55.7**	**3.7**	(2.3)	**0.2 %**	(0.1)%
Wholesale					
Non-affiliates	**5.0**	**(8.7)**	(6.5)		
Affiliates	**4.6**	**9.6**	31.1		
Total wholesale	**9.6**	**(0.9)**	6.6		
Total energy sales	**65.3**	**3.0%**	(1.0)%		

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 2018 were 3.7% higher than in 2017. Residential sales and commercial sales increased 8.2% and 1.9% in 2018, respectively, primarily due to colder weather in the first quarter and warmer weather in the second and third quarters 2018 as compared to the corresponding periods in 2017. Weather-adjusted residential sales were 0.4% lower in 2018 primarily due to lower customer usage resulting from an increase in penetration of energy-efficient residential appliances. Weather-adjusted commercial sales were 1.0% lower in 2018 primarily due to lower customer usage resulting from customer initiatives in energy savings and an ongoing migration to the electronic commerce business model. Industrial sales increased 1.4% in 2018 as compared to 2017 as a result of an increase in demand resulting from changes in production levels primarily in the primary metals, pipelines, and mining sectors offset by the paper sector.

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.

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 related to changes in price and KWH sales.

Fuel and Purchased Power Expenses

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, Alabama Power purchases a portion of its electricity needs from the wholesale market.

Details of Alabama Power's generation and purchased power were as follows:

	2018	2017	2016
Total generation *(in billions of KWHs)*	**60.5**	60.3	60.2
Total purchased power *(in billions of KWHs)*	**8.1**	6.4	7.1
Sources of generation *(percent)* —			
Coal	**50**	50	53
Nuclear	**23**	24	23
Gas	**19**	20	19
Hydro	**8**	6	5
Cost of fuel, generated *(in cents per net KWH)* —			
Coal	**2.73**	2.60	2.75
Nuclear	**0.77**	0.75	0.78
Gas	**2.84**	2.72	2.67
Average cost of fuel, generated *(in cents per net KWH)*[(a)(b)]	**2.26**	2.14	2.26
Average cost of purchased power *(in cents per net KWH)*[(c)]	**5.47**	5.29	4.80

(a) For 2018, cost of fuel, generated and average cost of fuel, generated excludes a $30 million adjustment associated with a May 2018 Alabama PSC accounting order related to excess deferred income taxes. See FUTURE EARNINGS POTENTIAL – "Retail Regulatory Matters – Tax Reform Accounting Order" herein for additional information.

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

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

Fuel and purchased power expenses were $1.73 billion in 2018, an increase of $180 million, or 11.6%, compared to 2017. The increase was primarily due to an $81 million net increase related to the volume of KWHs purchased and generated, a $54 million increase in the average cost of fuel, and a $15 million increase in the average cost of purchased power.

In addition, fuel expense increased $30 million in 2018 as a result of an Alabama PSC accounting order authorizing the amortization of a regulatory liability to offset under recovered fuel costs. See FUTURE EARNINGS POTENTIAL – "Retail Regulatory Matters – Tax Reform Accounting Order" herein for additional information.

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 energy transactions do not have a significant impact on earnings, since energy expenses are generally offset by energy revenues through Alabama Power's energy cost recovery clause. Alabama Power, along with the Alabama PSC, continuously monitors the under/over recovered balance to determine whether adjustments to billing rates are required. See Note 2 to the financial statements under "Alabama Power – Rate ECR" for additional information.

Fuel

Fuel expenses were $1.3 billion in 2018, an increase of $76 million, or 6.2%, compared to 2017. The increase was primarily due to a 5.0% increase in the average cost of KWHs generated by coal and a 4.4% increase in the average cost of KWHs generated by natural gas, which excludes tolling agreements. These increases were partially offset by a 28.3% increase in the volume of KWHs generated by hydro and a 2.1% decrease in the volume of KWHs generated by natural gas. 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.

In addition, fuel expense increased $30 million in 2018 as a result of an Alabama PSC accounting order authorizing the amortization of a regulatory liability to offset under recovered fuel costs. See FUTURE EARNINGS POTENTIAL – "Retail Regulatory Matters – Tax Reform Accounting Order" herein for additional information.

Purchased Power – Non-Affiliates

Purchased power expense from non-affiliates was $216 million in 2018, an increase of $46 million, or 27.1%, compared to 2017. This increase was primarily due to an 18.9% increase in the amount of energy purchased due to colder weather in the first quarter and warmer weather in the second and third quarters 2018 as compared to the corresponding periods in 2017 and a 6.6% increase in the average cost per KWH purchased due to higher natural gas prices. Purchased power expense from non-affiliates was $170 million in 2017, an increase of $4 million, or 2.4%, compared to 2016.

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

Purchased Power – Affiliates

Purchased power expense from affiliates was $216 million in 2018, an increase of $58 million, or 36.7%, compared to 2017. This increase was primarily due to a 34.5% increase in the amount of energy purchased due to colder weather in the first quarter and warmer weather in the second and third quarters 2018 as compared to the corresponding periods in 2017 and a 1.4% increase in the average cost per KWH purchased due to higher natural gas prices. 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.

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 2018, other operations and maintenance expenses decreased $40 million, or 2.3%, as compared to the prior year. Generation costs decreased $34 million primarily due to fewer outages resulting in lower costs. Employee benefit costs, including pension costs, decreased $26 million primarily due to lower active medical costs. Customer service costs decreased $10 million primarily due to cost-saving initiatives. These decreases were partially offset by a $47 million increase in expenses from unregulated sales of products and services that were reclassified as other operations and maintenance expenses as a result of the adoption of ASC 606. In prior periods, these expenses were included in other income (expense), net. See Note 1 to the financial statements under "Revenue" for additional information.

In 2017, other operations and maintenance expenses increased $152 million, or 9.8%, 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 $32 million.

See Note 11 to the financial statements under "Pension Plans" for additional information.

Depreciation and Amortization

Depreciation and amortization increased $28 million, or 3.8%, in 2018 as compared to the prior year primarily due to additional plant in service related to distribution, transmission, compliance-related steam, and other generation production projects. 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 5 to the financial statements under "Depreciation and Amortization" for additional information.

Allowance for Equity Funds Used During Construction

AFUDC equity increased $23 million, or 59.0%, in 2018 as compared to the prior year. The increase was primarily associated with steam and transmission construction projects. 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. 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 $18 million, or 5.9%, in 2018 as compared to the prior year primarily due to an increase in debt outstanding and higher interest rates, partially offset by an increase in the amounts capitalized. Interest

expense, net of amounts capitalized increased $3 million, or 1.0%, in 2017 as compared to the prior year. See FUTURE EARNINGS POTENTIAL – "Financing Activities" herein for additional information.

Other Income (Expense), Net

Other income (expense), net decreased $23 million, or 53.5%, in 2018 as compared to the prior year primarily due to an increase in charitable donations and the reclassification of revenues and expenses associated with unregulated sales of products and services to other revenues and operations and maintenance expenses, respectively, as a result of the adoption of ASC 606. See Note 1 to the financial statements under "Revenue" for additional information. Other income (expense), net increased $17 million, or 65.4%, in 2017 as compared to the prior year primarily due to increases in unregulated lighting services and a decrease in the non-service cost components of net periodic pension and other postretirement benefits costs. See Note 1 to the financial statements under "Recently Adopted Accounting Standards" and Note 11 to the financial statements for additional information on net periodic pension and other postretirement benefit costs.

Income Taxes

Income taxes decreased $277 million, or 48.8%, in 2018 as compared to the prior year primarily due to the reduction in the federal income tax rate, the benefit from the flowback of excess deferred income taxes as a result of the Tax Reform Legislation, and lower pre-tax earnings. 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 related to 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 net income as a result of the 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 10 to the financial statements for additional information.

Effects of Inflation

Alabama Power 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 Alabama Power's results of operations has not been substantial in recent years. See Note 2 to the financial statements under "Alabama Power – Rate RSE" for additional information.

FUTURE EARNINGS POTENTIAL

General

Alabama Power 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 Alabama Power to retail customers are set by the Alabama PSC under cost-based regulatory principles. Retail rates and earnings are reviewed and may be adjusted periodically within certain limitations. Prices for wholesale electric service, interconnecting transmission lines, and the exchange of electric power are regulated by the FERC. See ACCOUNTING POLICIES – "Application of Critical Accounting Policies and Estimates – Utility Regulation" herein and Note 2 to the financial statements under "Alabama Power" 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 Alabama Power's future earnings depends on numerous factors that affect the opportunities, challenges, and risks of Alabama Power's primary business of providing electric service. These factors include Alabama Power's ability to maintain a constructive regulatory environment that continues to allow for the timely recovery of prudently-incurred costs during a time of increasing costs and the weak pace of growth in new customers and electricity use per customer, especially in residential and commercial markets. 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 Alabama Power'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.

Environmental Matters

Alabama Power'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. Alabama Power maintains comprehensive environmental compliance and GHG strategies to assess upcoming requirements and compliance costs associated with these environmental laws and regulations. The costs, including capital expenditures, operations and maintenance costs, and costs reflected in ARO liabilities, required to comply with environmental laws and regulations and to achieve stated goals may impact future electric generating unit retirement and replacement decisions, results of operations, cash flows, and/or financial condition. Related costs may result from the installation of additional environmental controls, closure and monitoring of CCR facilities, unit retirements, or changing fuel sources for certain existing units, as well as related upgrades to Alabama Power's transmission and distribution systems. A major portion of these costs is expected to be recovered through existing ratemaking provisions. The ultimate impact of environmental laws and regulations and the GHG goals discussed herein will depend on various factors, such as state adoption and implementation of requirements, the availability and cost of any deployed technology, fuel prices, and the outcome of pending and/or future legal challenges.

New or revised environmental laws and regulations could affect many areas of Alabama Power'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 recovered in rates on a timely basis. Environmental compliance costs are recovered through Rate CNP Compliance. See Note 2 to the financial statements under "Alabama Power – 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/or 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 2018, Alabama Power has invested approximately $5.4 billion in environmental capital retrofit projects to comply with environmental requirements, with annual totals of approximately $681 million, $491 million, and $260 million for 2018, 2017, and 2016, 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, Alabama Power's current compliance strategy estimates capital expenditures of $635 million from 2019 through 2023, with annual totals of approximately $226 million in 2019, $68 million in 2020, $118 million in 2021, $112 million in 2022, and $111 million in 2023. These estimates do not include any potential compliance costs associated with pending regulation of CO_2 emissions from fossil fuel-fired electric generating units. See "Global Climate Issues" herein for additional information. Alabama Power also anticipates substantial expenditures associated with ash pond closure and ground water monitoring under the CCR Rule, which are reflected in Alabama Power's ARO liabilities. See FINANCIAL CONDITION AND LIQUIDITY – "Capital Requirements and Contractual Obligations" herein and Note 6 to the financial statements 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) to protect and improve the nation's air quality, which it reviews and revises periodically. Following a NAAQS revision, states are required to develop an EPA-approved plan to protect air quality. These state plans 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 electric generating facilities. No areas within Alabama Power's service territory are currently designated nonattainment for any NAAQS. If 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) to address impacts of SO_2 and NO_X emissions from fossil fuel-fired electric generating plants. CSAPR establishes emissions trading programs and budgets for certain states and allocates emissions allowances for sources in those states. In 2016, the EPA published a final rule establishing more stringent ozone season NO_X emissions budgets in Alabama. Increases in either future fossil fuel-fired generation or the availability or cost of CSAPR allowances could have a negative financial impact on results of operations for Alabama Power.

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 demonstrating continued reasonable progress towards achieving visibility improvement goals. The EPA approved the regional progress SIP for the State of Alabama.

Water Quality

In 2014, the EPA finalized requirements under Section 316(b) of the Clean Water Act (CWA) to regulate cooling water intake structures (CWIS) to minimize their effects on fish and other aquatic life at existing power plants (e.g. coal, natural gas, oil, and nuclear generating plants) and manufacturing facilities. The regulation requires plant-specific studies to determine applicable CWIS changes to protect organisms that either get caught on the intake screens (impingement) or are drawn into the cooling system (entrainment). Alabama Power is conducting these studies and currently anticipates applicable CWIS changes may include fish-friendly CWIS screens with fish return systems and minor additions of monitoring equipment at certain plants. However, the ultimate impact of this rule will depend on the outcome of these plant-specific studies, any additional protective measures required to be incorporated into each plant's National Pollutant Discharge Elimination System (NPDES) permit based on site-specific factors, and the outcome of any legal challenges.

In 2015, the EPA finalized the steam electric effluent limitations guidelines (ELG) rule (2015 ELG Rule) that set national standards for wastewater discharges from new and existing steam electric generating units generating greater than 50 MWs. The 2015 ELG Rule prohibits effluent discharges of certain waste streams and imposes stringent limits on flue gas desulfurization (scrubber) wastewater discharges. The revised technology-based limits and the CCR Rule require extensive changes to existing ash and wastewater management systems or the installation and operation of new ash and wastewater management systems. Compliance with the 2015 ELG Rule is expected to require capital expenditures and increased operational costs primarily for Alabama Power's coal-fired electric generation. State environmental agencies will incorporate specific compliance applicability dates in the NPDES permitting process for each ELG waste stream no later than December 31, 2023. The EPA is scheduled to issue a new rulemaking by December 2019 that could revise the limitations and applicability dates of two of the waste streams regulated in the 2015 ELG Rule. The impact of any changes to the 2015 ELG Rule will depend on the content of the new rule and the outcome of any legal challenges. Alabama Power does not anticipate that the unavailability of any units as a result of the ELG rule will have a material impact on Alabama Power'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, canals, and wastewater treatment ponds), which could impact new generation projects and permitting and reporting requirements associated with the installation, expansion, and maintenance of transmission and distribution projects. The EPA and the Corps are expected to publish a final rule in 2019 to replace the 2015 WOTUS definition. The impact of any changes to the 2015 WOTUS rule will depend on the content of this final rule and the outcome of any legal challenges.

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 (ash ponds) at active generating power plants. In addition to the EPA's CCR Rule, the State of Alabama has also finalized regulations regarding the handling of CCR that have been provided to the EPA for review. This state CCR rule is generally consistent with the federal CCR Rule. The EPA's CCR Rule requires landfills and ash ponds to be evaluated against a set of performance criteria and potentially closed if minimum criteria are not met. Closure of existing landfills and ash ponds could require installation of equipment and infrastructure to manage CCR in accordance with the CCR Rule. Based on cost estimates for closure in place and monitoring of ash ponds pursuant to the CCR Rule, Alabama Power recorded AROs for each CCR unit in 2015. As further analysis was performed and closure details were developed, Alabama Power has continued to periodically update these cost estimates, as discussed further below.

The EPA published certain amendments to the CCR Rule, which became effective August 29, 2018. These amendments extend the date from April 2019 to October 31, 2020 to cease sending CCR and other waste streams to ash ponds that demonstrate compliance with all except two of the specified performance criteria.

On August 21, 2018, the U.S. Court of Appeals for the District of Columbia Circuit issued a decision suggesting the EPA should regulate previously-excluded inactive ash ponds located at retired generation facilities and questioning both the ability of unlined ash ponds to continue operating no matter the performance criteria results and the classification of clay-lined landfills and ash ponds. These developments could impact the expected timing of Alabama Power's landfill and ash pond closure activities, but the extent of any impact will depend on the outcome of ongoing litigation, anticipated EPA rulemaking action to establish further guidance, and the outcome of any legal challenges.

In June 2018, Alabama Power recorded an increase of approximately $1.2 billion to its AROs related to the CCR Rule. The revised cost estimates were based on information from feasibility studies performed on ash ponds in use at plants operated by Alabama Power. During the second quarter 2018, Alabama Power's management completed its analysis of these studies which indicated that additional closure costs, primarily related to increases in estimated ash volume, water management requirements,

and design revisions, will be required to close these ash ponds under the planned closure-in-place methodology. As the level of work becomes more defined in the next 12 months, it is likely that these cost estimates will change and the change could be material.

Alabama Power expects to periodically update its ARO cost estimates. Absent continued recovery of ARO costs through regulated rates, Alabama Power's results of operations, cash flows, and financial condition could be materially impacted. See FINANCIAL CONDITION AND LIQUIDITY – "Capital Requirements and Contractual Obligations" herein and Note 6 to the financial statements for additional information.

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

Nuclear Decommissioning

In June 2018, Alabama Power completed an updated decommissioning cost site study for Plant Farley. The estimated cost of decommissioning based on the study resulted in an increase in Alabama Power's ARO liability of approximately $300 million. Amounts previously contributed to Alabama Power's external trust funds are currently projected to be adequate to meet the updated decommissioning obligations. See Note 6 to the financial statements for additional information.

Global Climate Issues

On August 31, 2018, the EPA published a proposed rule known as the Affordable Clean Energy (ACE) Rule, which is intended to replace a regulation enacted in 2015 known as the Clean Power Plan (CPP), that would limit CO_2 emissions from existing fossil fuel-fired electric generating units. The CPP has been stayed by the U.S. Supreme Court since 2016. The ACE Rule would require states to develop GHG unit-specific emission rate standards based on heat-rate efficiency improvements for existing fossil fuel-fired steam units. As proposed, combustion turbines, including natural gas combined cycles, are not affected sources. As of January 1, 2019, Alabama Power has ownership interests in 20 fossil fuel-fired steam units to which the proposed ACE Rule is applicable. The ultimate impact of this rule to Alabama Power is currently unknown and will depend on changes between the proposal and the final rule, subsequent state plan developments and requirements, and any associated legal challenges.

On December 20, 2018, the EPA published a proposed review of the Standards of Performance for Greenhouse Gas Emissions from New, Modified, and Reconstructed Stationary Sources: Electric Utility Generating Units final rule (2015 NSPS rule). The EPA's final 2015 NSPS rule set standards of performance for new, modified, and reconstructed electric utility generating units which included stationary combustion turbines and fossil-fired steam boilers. This proposal reduces the stringency of the 2015 NSPS rule by not basing the new and reconstructed fossil-fired steam boiler and IGCC standards on partial carbon capture and sequestration. The impact of any changes to this rule will depend on the content of the final rule and the outcome of any legal challenges.

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, Alabama Power's 2017 GHG emissions were approximately 37 million metric tons of CO_2 equivalent. The preliminary estimate of Alabama Power's 2018 GHG emissions on the same basis is approximately 36 million metric tons of CO_2 equivalent.

Through 2017, the Southern Company system has achieved an estimated GHG emission reduction of 36% since 2007. In April 2018, Southern Company established an intermediate goal of a 50% reduction in carbon emissions from 2007 levels by 2030 and a long-term goal of low- to no-carbon operations by 2050. To achieve these goals, the Southern Company system expects to continue growing its renewable energy portfolio, optimize technology advancements to modernize its transmission and distribution systems, increase the use of natural gas for generation, complete ongoing construction projects, invest in energy efficiency, and continue research and development efforts focused on technologies to lower GHG emissions. The Southern Company system's ability to achieve these goals also will be dependent on many external factors, including supportive national energy policies, low natural gas prices, and the development, deployment, and advancement of relevant energy technologies.

FERC Matters

Open Access Transmission Tariff

On May 10, 2018, AMEA and Cooperative Energy filed with the FERC a complaint against SCS and the traditional electric operating companies (including Alabama Power) claiming that the current 11.25% base ROE used in calculating the annual transmission revenue requirements of the traditional electric operating companies' (including Alabama Power's) open access transmission tariff is unjust and unreasonable as measured by the applicable FERC standards. The complaint requested that the base ROE be set no higher than 8.65% and that the FERC order refunds for the difference in revenue requirements that results from applying a just and reasonable ROE established in this proceeding upon determining the current ROE is unjust and

unreasonable. On June 18, 2018, SCS and the traditional electric operating companies (including Alabama Power) filed their response challenging the adequacy of the showing presented by the complainants and offering support for the current ROE. On September 6, 2018, the FERC issued an order establishing a refund effective date of May 10, 2018 in the event a refund is due and initiating an investigation and settlement procedures regarding the current base ROE. Through December 31, 2018, the estimated maximum potential refund is not expected to be material to Alabama Power's results of operations or cash flows. The ultimate outcome of this matter cannot be determined at this time.

Retail Regulatory Matters

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 2 to the financial statements under "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 common equity return (WCER) 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%. When the projected WCER is under the allowed range, there is an adjusting point of 5.98% and eligibility for a performance-based adder of seven basis points, or 0.07%, to the WCER 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. If Alabama Power's actual retail return is above the allowed WCER 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 WCER range. Prior to January 2019, retail rates remained unchanged when the WCER range was between 5.75% and 6.21%.

On May 1, 2018, the Alabama PSC approved modifications to Rate RSE and other commitments designed to position Alabama Power to address the growing pressure on its credit quality resulting from the Tax Reform Legislation, without increasing retail rates under Rate RSE in the near term. Alabama Power plans to reduce growth in total debt by increasing equity, with corresponding reductions in debt issuances, thereby de-leveraging its capital structure. Alabama Power's goal is to achieve an equity ratio of approximately 55% by the end of 2025. At December 31, 2018, Alabama Power's equity ratio was approximately 47%.

The approved modifications to Rate RSE began for billings in January 2019. The modifications include reducing the top of the allowed WCER range from 6.21% to 6.15% and modifications to the refund mechanism applicable to prior year actual results. The modifications to the refund mechanism allow Alabama Power to retain a portion of the revenue that causes the actual WCER for a given year to exceed the allowed range.

Generally, if Alabama Power's actual WCER is between 6.15% and 7.65%, customers will receive 25% of the amount between 6.15% and 6.65%, 40% of the amount between 6.65% and 7.15%, and 75% of the amount between 7.15% and 7.65%. Customers will receive all amounts in excess of an actual WCER of 7.65%.

In conjunction with these modifications to Rate RSE, on May 8, 2018, Alabama Power consented to a moratorium on any upward adjustments under Rate RSE for 2019 and 2020 and will also return $50 million to customers through bill credits in 2019.

On November 30, 2018, Alabama Power made its required annual Rate RSE submission to the Alabama PSC of projected data for calendar year 2019. Projected earnings were within the specified range; therefore, retail rates under Rate RSE remain unchanged for 2019.

At December 31, 2018, Alabama Power's retail return exceeded the allowed WCER range, which resulted in Alabama Power establishing a regulatory liability of $109 million for Rate RSE refunds. In accordance with an Alabama PSC order issued on February 5, 2019, Alabama Power will apply $75 million to reduce the Rate ECR under recovered balance and the remaining $34 million will be refunded to customers through bill credits in July through September 2019.

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. No adjustments to Rate CNP PPA occurred during the period 2016 through 2018 and no adjustment is expected in 2019.

In accordance with an accounting order issued in February 2017 by the Alabama PSC, Alabama Power reclassified $69 million of the December 31, 2016 Rate CNP PPA under recovered balance 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 no later than 2022.

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 Alabama Power'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 in February 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 no later than 2022.

On November 30, 2018, Alabama Power submitted calculations associated with its cost of complying with environmental mandates, as provided under Rate CNP Compliance. The filing reflected a projected unrecovered retail revenue requirement for environmental compliance of approximately $205 million, which is being recovered in the billing months of January 2019 through December 2019.

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 Alabama Power'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 in February 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 no later than 2022. Alabama Power's current depreciation study became effective January 1, 2017.

On May 1, 2018, the Alabama PSC approved an increase to Rate ECR from 2.015 cents per KWH to 2.353 cents per KWH effective July 2018 through December 2018. On December 4, 2018, the Alabama PSC issued a consent order to leave this rate in effect through December 31, 2019. This change is expected to increase collections by approximately $183 million in 2019. Absent any further order from the Alabama PSC, in January 2020, the rates will return to the originally authorized 5.910 cents per KWH.

As discussed herein under "Rate RSE," in accordance with an Alabama PSC order issued on February 5, 2019, Alabama Power will utilize $75 million of the 2018 Rate RSE refund liability to reduce the Rate ECR under recovered balance.

Tax Reform Accounting Order

On May 1, 2018, the Alabama PSC approved an accounting order that authorized Alabama Power to defer the benefits of federal excess deferred income taxes associated with the Tax Reform Legislation for the year ended December 31, 2018 as a regulatory liability and to use up to $30 million of such deferrals to offset under recovered amounts under Rate ECR. The estimated deferrals for the year ended December 31, 2018 totaled approximately $63 million, subject to adjustment following the filing of the 2018 tax return, of which $30 million was used to offset the Rate ECR under recovered balance and $33 million is recorded in other

regulatory liabilities, deferred on the balance sheet to be used for the benefit of customers as determined by the Alabama PSC at a future date. See Note 10 to the financial statements under "Current and Deferred Income Taxes" for additional information.

Software Accounting Order

On February 5, 2019, the Alabama PSC approved an accounting order that authorizes Alabama Power to establish a regulatory asset for operations and maintenance costs associated with software implementation projects. The regulatory asset will be amortized ratably over the life of the related software.

Plant Greene County

Alabama Power jointly owns Plant Greene County with an affiliate, Mississippi Power. See Note 5 to the financial statements under "Joint Ownership Agreements" for additional information regarding the joint ownership agreement. On August 6, 2018, Mississippi Power filed its proposed Reserve Margin Plan (RMP) with the Mississippi PSC, which proposes a four-year acceleration of the retirement of Plant Greene County Units 1 and 2 to the third quarter 2021 and the third quarter 2022, respectively. Mississippi Power's proposed Plant Greene County unit retirements would require the completion of proposed transmission and system reliability improvements, as well as agreement by Alabama Power. Alabama Power will continue to monitor the status of Mississippi Power's proposed RMP and associated regulatory process as well as the proposed transmission and system reliability improvements. Alabama Power will review all the facts and circumstances and will evaluate all its alternatives prior to reaching a final determination on the ongoing operations of Plant Greene County. The ultimate outcome of this matter cannot be determined at this time.

Request for Proposals for Future Generation

On September 21, 2018, Alabama Power issued a request for proposals of between 100 MWs and 1,200 MWs of capacity beginning no later than 2023. On November 9, 2018, bids were received and an evaluation of those bids is in progress. Any purchases will depend upon the cost competitiveness of the respective offers as well as other options available to Alabama Power. The ultimate outcome of this matter cannot be determined at this time.

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. 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, 2018 was $20 million and is included in other regulatory liabilities, deferred on the balance sheet.

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.

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 (Environmental Accounting Order), 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 is being amortized and recovered over the affected unit's remaining useful life, as established prior to the decision regarding early retirement through Rate CNP Compliance. At December 31, 2018, this regulatory asset had a balance of $42 million. See "Environmental Matters – Environmental Laws and Regulations" herein for additional information regarding environmental regulations.

Subsequent to December 31, 2018, Alabama Power determined that Plant Gorgas Units 8, 9, and 10 (approximately 1,000 MWs) will be retired by April 15, 2019 due to the expected costs of compliance with federal and state environmental regulations. In accordance with the Environmental Accounting Order, approximately $740 million of net investment costs will be transferred to a regulatory asset at the retirement date and recovered over the affected units' remaining useful lives, as established prior to the decision to retire.

Income Tax Matters

Federal Tax Reform Legislation

In December 2017, the Tax Reform Legislation was signed into law and became effective on January 1, 2018. The Tax Reform Legislation, among other things, reduced the federal corporate income tax rate to 21%, retained normalization provisions for public utility property and existing renewable energy incentives, and repealed the corporate alternative minimum tax. 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. See Note 10 to the financial statements for information on Southern Company's joint consolidated income tax allocation agreement.

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 provided 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, Alabama Power considered all amounts recorded in the financial statements as a result of the Tax Reform Legislation "provisional" as discussed in SAB 118 and subject to revision prior to filing its 2017 tax return in the fourth quarter 2018. Alabama Power recognized tax expense of $3 million in 2017 as a result of the Tax Reform Legislation. In addition, in total, Alabama Power recorded a $281 million decrease in regulatory assets and a $2.0 billion increase in regulatory liabilities as a result of the Tax Reform Legislation. As of December 31, 2018, Alabama Power considered the measurement of impacts from the Tax Reform Legislation on deferred income tax assets and liabilities, primarily due to the impact of the reduction of the corporate income tax rate, to be complete.

However, the IRS continues to issue regulations that provide further interpretation and guidance on the law and each state's adoption of the provisions contained in the Tax Reform Legislation remains uncertain. The regulatory treatment of certain impacts of the Tax Reform Legislation is subject to the discretion of the FERC. The ultimate impact of this matter cannot be determined at this time. See Note 2 to the financial statements under "Alabama Power – Rate RSE" for additional information regarding modifications to Rate RSE to reflect the impacts of the Tax Reform Legislation. Also see FINANCIAL CONDITION AND LIQUIDITY – "Credit Rating Risk" herein and Note 10 to the financial statements under "Current and Deferred Income Taxes" for additional information.

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 $100 million for the 2018 tax year and approximately $30 million for the 2019 tax year. See Note 10 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.

Other Matters

Alabama Power is involved in various other matters being litigated and regulatory matters that could affect future earnings. In addition, Alabama Power is subject to certain claims and legal actions arising in the ordinary course of business. Alabama Power's business activities are subject to extensive governmental regulation related to public health and the environment, such as laws and regulations governing air, water, land, and protection of other natural resources. Litigation over environmental issues and claims of various types, including property damage, personal injury, common law nuisance, and citizen enforcement of environmental laws and regulations, 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 Notes 2 and 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 Alabama Power's financial statements. See Notes 2 and 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

Alabama Power prepares its financial statements in accordance with GAAP. Significant accounting policies are described in Notes 1, 5, and 6 to the financial statements. In the application of these policies, certain estimates are made that may have a material impact on Alabama Power'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

Alabama Power is subject to retail regulation by the Alabama PSC and wholesale regulation by the FERC. As a result, Alabama Power 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 Alabama Power'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 Alabama Power; 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 Alabama Power's results of operations and financial condition than they would on a non-regulated company.

As reflected in Note 2 to the financial statements under "Alabama Power – Regulatory Assets and Liabilities," 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 Alabama Power's financial statements.

Asset Retirement Obligations

AROs are computed as the fair value of the estimated costs for an asset's future retirement and are recorded in the period in which the liability is incurred. The estimated 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 Alabama Power's nuclear facility, Plant Farley, and facilities that are subject to the CCR Rule and the related state rule, principally ash ponds. In addition, Alabama Power has AROs 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.

Alabama Power 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 retirement obligations will be recognized when sufficient information becomes available to support a reasonable estimation of the retirement obligation.

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. In June 2018, Alabama Power recorded increases of approximately $1.2 billion

to its AROs related to the CCR Rule and approximately $300 million to its AROs related to updated nuclear decommissioning cost site studies. The revised CCR-related cost estimates as of June 30, 2018 were based on information from feasibility studies performed on ash ponds in use at the plants Alabama Power operates. During the second quarter 2018, Alabama Power's management completed its analysis of these studies which indicated that additional closure costs, primarily related to increases in estimated ash volume, water management requirements, and design revisions, will be required to close these ash ponds under the planned closure-in-place methodology. As the level of work becomes more defined in the next 12 months, it is likely that these cost estimates will change and the change could be material. Alabama Power expects to periodically update its ARO cost estimates. See FUTURE EARNINGS POTENTIAL – "Environmental Matters – Environmental Laws and Regulations – Coal Combustion Residuals" herein and Note 6 to the financial statements for additional information.

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

Pension and Other Postretirement Benefits

Alabama Power'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 Alabama Power believes that the assumptions used are appropriate, differences in actual experience or significant changes in assumptions would affect its pension and other postretirement benefit costs and obligations.

Key elements in determining Alabama Power'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 Alabama Power's liability related to the pension and other postretirement benefit plans, Southern 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.

A 25 basis point change in any significant assumption (discount rate, salary increases, or long-term rate of return on plan assets) would result in a $9 million or less change in total annual benefit expense, a $99 million or less change in the projected obligation for the pension plan, and an $11 million or less change in the projected obligation for other post retirement benefit plans.

Alabama Power recorded pension costs of $27 million, $9 million, and $11 million in 2018, 2017, and 2016, respectively. Postretirement benefit costs for Alabama Power were $2 million, $3 million, and $4 million in 2018, 2017, and 2016, 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 11 to the financial statements for additional information regarding pension and other postretirement benefits.

Contingent Obligations

Alabama Power 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 Notes 2 and 3 to the financial statements for more information regarding certain of these contingencies. Alabama Power 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 Alabama Power's results of operations, cash flows, or financial condition.

Recently Issued Accounting Standards

See Note 1 to the financial statements under "Recently Adopted Accounting Standards" for additional information.

In 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 Alabama Power adopted the new standard effective January 1, 2019.

Alabama Power elected the transition methodology provided by ASU No. 2018-11, *Leases (Topic 842): Targeted Improvements*, whereby the requirements of ASU 2016-02 are applied on a prospective basis as of the adoption date of January 1, 2019, without restating prior periods. Alabama Power elected the package of practical expedients provided by ASU 2016-02 that allows prior determinations of whether existing contracts are, or contain, leases and the classification of existing leases to continue without reassessment. Additionally, Alabama Power applied the use-of-hindsight practical expedient in determining lease terms as of the date of adoption and elected the practical expedient that allows existing land easements not previously accounted for as leases not to be reassessed. Alabama Power also made accounting policy elections to account for short-term leases in all asset classes as off-balance sheet leases and combined lease and non-lease components in the computations of lease obligations and right-of-use assets for most asset classes.

Alabama Power completed the implementation of a new application to track and account for its leases and updated its internal controls and accounting policies to support the accounting for leases under ASU 2016-02. Alabama Power completed its lease inventory and determined its most significant leases involve PPAs. In the first quarter 2019, the adoption of ASU 2016-02 resulted in recording lease liabilities and right-of-use assets on Alabama Power's balance sheet each totaling approximately $195 million, with no impact on Alabama Power's statement of income.

FINANCIAL CONDITION AND LIQUIDITY

Overview

Alabama Power's financial condition remained stable at December 31, 2018. Alabama Power'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 and closures of ash ponds, to expand and improve transmission and distribution facilities, and for restoration following major storms. Operating cash flows provide a substantial portion of Alabama Power's cash needs. For the three-year period from 2019 through 2021, Alabama Power's projected common stock dividends, capital expenditures, and debt maturities are expected to exceed operating cash flows. Alabama Power 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. Alabama Power plans to use commercial paper to manage seasonal variations in operating cash flows and for other working capital needs. Alabama Power 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.

Alabama Power's investments in the qualified pension plan and the nuclear decommissioning trust funds decreased in value as of December 31, 2018 as compared to December 31, 2017. No contributions to the qualified pension plan were made for the year ended December 31, 2018 and no mandatory contributions to the qualified pension plan are anticipated during 2019. Alabama Power's funding obligations for the nuclear decommissioning trust funds are based on the most recent site study completed in 2018, and the next study is expected to be conducted by 2023. See Notes 6 and 11 to the financial statements under "Nuclear Decommissioning" and "Pension Plans," respectively, for additional information.

Net cash provided from operating activities totaled $1.9 billion for 2018, an increase of $44 million as compared to 2017. The increase in cash provided from operating activities was primarily due to an increase in weather-related revenues, fuel cost recovery, and income tax refunds received in 2018, partially offset by materials and supplies purchases, the timing of vendor payments, and settlement of AROs. Net cash provided from operating activities totaled $1.8 billion for 2017, a decrease of $112 million as compared to 2017. 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 used for investing activities totaled $2.3 billion for 2018, $1.9 billion for 2017, and $1.4 billion for 2016. These activities were primarily related to gross property additions for environmental, distribution, transmission, and steam generation assets.

Net cash provided from financing activities totaled $177 million in 2018 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 a maturity of long-term debt. 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. 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 2018 included increases of $2.84 billion in property, plant, and equipment primarily due to $1.35 billion in AROs and additions to nuclear, distribution, and transmission assets. Other changes include $522 million in capital contributions from Southern Company and $295 million in long-term debt primarily due to a senior notes issuance. See Notes 6 and 8 to the financial statements for additional information related to changes in Alabama Power's AROs and financing activities, respectively.

Alabama Power's ratio of common equity to total capitalization plus short-term debt was 47.0% and 46.3% at December 31, 2018 and 2017, respectively. See Note 8 to the financial statements for additional information.

Sources of Capital

Alabama Power 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. Subsequent to December 31, 2018, Alabama Power received a capital contribution totaling $1.225 billion from Southern Company.

Security issuances are subject to regulatory approval by the Alabama PSC. Additionally, with respect to the public offering of securities, Alabama Power 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.

Alabama Power obtains financing separately without credit support from any affiliate. See Note 8 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 Alabama Power are not commingled with funds of any other company in the Southern Company system.

At December 31, 2018, Alabama Power's current liabilities exceeded current assets by $50 million. Alabama Power'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, 2018, Alabama Power had approximately $313 million of cash and cash equivalents. Committed credit arrangements with banks at December 31, 2018 were as follows:

Expires					Expires Within One Year	
2019	2020	2022	Total	Unused	Term Out	No Term Out
(in millions)			*(in millions)*		*(in millions)*	
$ 33	$ 500	$ 800	$ 1,333	$ 1,333	$ —	$ 33

See Note 8 to the financial statements under "Bank Credit Arrangements" for additional information.

Most of these bank credit arrangements, as well as Alabama Power's term loan arrangements, contain covenants that limit debt levels and contain cross-acceleration provisions to other indebtedness (including guarantee obligations) of Alabama Power. Such cross-acceleration provisions to other indebtedness would trigger an event of default if Alabama Power defaulted on indebtedness, the payment of which was then accelerated. At December 31, 2018, Alabama Power 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, Alabama Power expects to renew or replace its bank credit arrangements as needed prior to expiration. In connection therewith, Alabama Power 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 Alabama Power'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 at December 31, 2018.

Alabama Power also has substantial cash flow from operating activities and access to the capital markets, including a commercial paper program, to meet liquidity needs. Alabama Power may meet short-term cash needs through its commercial paper program. Alabama Power 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 Alabama Power and the other traditional electric operating companies. Proceeds from such issuances for the benefit of Alabama Power are loaned directly to Alabama Power. 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 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, 2018	**$ —**	**—%**	**$ 27**	**2.3%**	**$ 258**
December 31, 2017	$ 3	3.7%	$ 25	1.3%	$ 223
December 31, 2016	$ —	—%	$ 16	0.6%	$ 200

(*) Average and maximum amounts are based upon daily balances during the 12-month periods ended December 31, 2018, 2017, and 2016.

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

Financing Activities

In June 2018, Alabama Power issued $500 million aggregate principal amount of Series 2018A 4.300% Senior Notes due July 15, 2048. The proceeds were used to repay outstanding commercial paper and for general corporate purposes, including Alabama Power's continuous construction program.

In October 2018, Alabama Power purchased and held $120 million aggregate principal amount of The Industrial Development Board of the City of Mobile, Alabama Pollution Control Revenue Bonds (Alabama Power Company Plant Barry Project), Series 2008. Alabama Power reoffered these bonds to the public in November 2018.

In November 2018, Alabama Power guaranteed a $100 million three-year bank term loan for SEGCO. See Note 9 to the financial statements under "Guarantees" for additional information.

Subsequent to December 31, 2018, Alabama Power repaid at maturity $200 million aggregate principal amount of Series Z 5.125% Senior Notes due February 15, 2019.

In addition to any financings that may be necessary to meet capital requirements and contractual obligations, Alabama Power 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, 2018, Alabama Power 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, 2018 were as follows:

Credit Ratings	Maximum Potential Collateral Requirements
	(in millions)
At BBB and/or Baa2	$ 1
At BBB- and/or Baa3	$ 1
Below BBB- and/or Baa3	$ 356

Included in these amounts are certain agreements that could require collateral in the event that either Alabama Power or Georgia Power (an affiliate of 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 Alabama Power to access capital markets and would be likely to impact the cost at which it does so.

On September 28, 2018, Fitch assigned a negative rating outlook to the ratings of Southern Company and certain of its subsidiaries (including Alabama Power).

Also on September 28, 2018, Moody's revised its rating outlook for Alabama Power from negative to stable.

As a result of 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 Alabama Power, may be negatively impacted. The modifications to Rate RSE and other commitments approved by the Alabama PSC are expected to help mitigate these potential adverse impacts to certain credit metrics and will help Alabama Power meet its goal of achieving an equity ratio of approximately 55% by the end of 2025. See Note 2 to the financial statements under "Alabama Power – Rate RSE" for additional information.

Market Price Risk

Due to cost-based rate regulation and other various cost recovery mechanisms, Alabama Power 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, Alabama Power nets the exposures, where possible, to take advantage of natural offsets and enters into various derivative transactions for the remaining exposures pursuant to Alabama Power's policies in areas such as counterparty exposure and risk management practices. Alabama Power'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, Alabama Power 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, 2018 was 2.5%. If Alabama Power 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, 2018. See Note 1 to the financial statements under "Financial Instruments" and Note 14 to the financial statements for additional information.

To mitigate residual risks relative to movements in electricity prices, Alabama Power 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. Alabama Power continues to manage a retail fuel-hedging program implemented per the guidelines of the Alabama PSC. Alabama Power had no material change in market risk exposure for the year ended December 31, 2018 when compared to the year ended December 31, 2017.

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 Alabama Power'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. Alabama Power 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 Alabama Power'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:

	2018 Changes	2017 Changes
	Fair Value	
	(in millions)	
Contracts outstanding at the beginning of the period, assets (liabilities), net	**$ (6)**	$ 12
Contracts realized or settled	**(2)**	(1)
Current period changes(*)	**4**	(17)
Contracts outstanding at the end of the period, assets (liabilities), net	**$ (4)**	$ (6)

(*) 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 at December 31, 2018 and 2017 were as follows:

	2018	2017
	mmBtu Volume	
	(in millions)	
Commodity – Natural gas swaps	**65**	64
Commodity – Natural gas options	**9**	5
Total hedge volume	**74**	69

The weighted average swap contract cost above market prices was approximately $0.08 per mmBtu at December 31, 2018 and December 31, 2017. 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 Alabama Power's retail energy cost recovery clause.

At December 31, 2018 and 2017, substantially all of Alabama Power's energy-related derivative contracts were designated as regulatory hedges and were related to Alabama Power'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.

Alabama Power 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 13 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, 2018 were as follows:

	Fair Value Measurements December 31, 2018		
	Total Fair Value	Maturity	
		Year 1	Years 2&3
		(in millions)	
Level 1	$ —	$ —	$ —
Level 2	(4)	(1)	(3)
Level 3	—	—	—
Fair value of contracts outstanding at end of period	$ (4)	$ (1)	$ (3)

Alabama Power is exposed to market price risk in the event of nonperformance by counterparties to energy-related and interest rate derivative contracts. Alabama Power 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, Alabama Power 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 14 to the financial statements.

Capital Requirements and Contractual Obligations

The construction program of Alabama Power is currently estimated to total $1.8 billion for 2019, $1.6 billion for 2020, $1.6 billion for 2021, $1.4 billion for 2022, and $1.5 billion for 2023. The construction program includes 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 $226 million for 2019, $68 million for 2020, $118 million for 2021, $112 million for 2022, and $111 million for 2023. These estimated expenditures do not include any potential compliance costs associated with pending 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.

Alabama Power also anticipates costs associated with closure-in-place and monitoring of ash ponds in accordance with the CCR Rule, which are reflected in Alabama Power's ARO liabilities. These costs, which are expected to change and could change materially as underlying assumptions are refined and the cost, method, and timing of compliance activities continue to be evaluated, are currently estimated to be $232 million for 2019, $238 million for 2020, $246 million for 2021, $252 million for 2022, and $258 million for 2023. See FUTURE EARNINGS POTENTIAL – "Environmental Matters – Environmental Laws and Regulations – Coal Combustion Residuals" herein and Note 6 to the financial statements 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 environmental rules; changes in generating plants, including unit retirements and replacements and adding or changing fuel sources at existing generating units, to meet regulatory requirements; changes in the expected environmental compliance program; changes in FERC rules and regulations; Alabama PSC approvals; changes in legislation; the cost and efficiency of construction labor, equipment, and materials; project scope and design changes; storm impacts; and the cost of capital. In addition, there can be no assurance that costs related to capital expenditures will be fully recovered.

As a result of NRC requirements, Alabama Power has external trust funds for nuclear decommissioning costs; however, Alabama Power currently has no additional funding requirements. For additional information, see Note 6 to the financial statements under "Nuclear Decommissioning."

In addition, as discussed in Note 11 to the financial statements, Alabama Power provides postretirement benefits to substantially all employees and funds trusts to the extent required by the Alabama PSC and the FERC.

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, other purchase commitments, and ARO settlements are detailed in the contractual obligations table that follows. See Notes 1, 6, 8, 9, 11, and 14 to the financial statements for additional information.

Contractual Obligations

Contractual obligations at December 31, 2018 were as follows:

	2019	2020-2021	2022-2023	After 2023	Total
			(in millions)		
Long-term debt[a] —					
Principal	$ 200	$ 560	$ 1,050	$ 6,377	$ 8,187
Interest	330	630	575	4,751	6,286
Preferred stock dividends[b]	15	29	29	—	73
Financial derivative obligations[c]	4	6	—	—	10
Operating leases[d]	12	17	9	1	39
Capital lease	1	1	1	1	4
Purchase commitments —					
Capital[e]	1,671	3,049	2,536	—	7,256
Fuel[f]	1,072	1,342	531	1,108	4,053
Purchased power[g]	83	178	140	512	913
Other[h]	42	61	61	277	441
ARO settlements[i]	232	485	510	—	1,227
Pension and other postretirement benefit plans[j]	16	32	—	—	48
Total	$ 3,678	$ 6,390	$ 5,442	$ 13,027	$ 28,537

(a) All amounts are reflected based on final maturity dates. Alabama Power 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, 2018, 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 14 to the financial statements.

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

(e) Alabama Power 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, capital expenditures covered under LTSAs, and estimated capital expenditures for AROs, which are reflected in "Fuel," "Other," and "ARO settlements," respectively. At December 31, 2018, 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 NYMEX future prices at December 31, 2018.

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

(h) Includes LTSAs and contracts for the procurement of limestone. LTSAs include price escalation based on inflation indices.

(i) Represents estimated costs for a five-year period associated with closing and monitoring ash ponds in accordance with the CCR Rule and the related state rule, which are reflected in Alabama Power's ARO liabilities. Material expenditures in future years for ARO settlements also will be required for ash ponds, nuclear decommissioning, and other liabilities reflected in Alabama Power's AROs. See FUTURE EARNINGS POTENTIAL – "Environmental Matters – Environmental Laws and Regulations – Coal Combustion Residuals" herein and Note 6 to the financial statements for additional information.

(j) Alabama Power forecasts contributions to the pension and other postretirement benefit plans over a three-year period. Alabama Power 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 Alabama Power's corporate assets. See Note 11 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 Alabama Power's corporate assets.

OVERVIEW

Business Activities

Georgia Power 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 Georgia Power'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, including CCR rules, reliability, fuel, capital expenditures, including new generating facilities and expanding and improving transmission and distribution facilities, and restoration following major storms. Georgia Power 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 Georgia Power for the foreseeable future. On April 3, 2018, the Georgia PSC approved the Georgia Power Tax Reform Settlement Agreement, which provides for a total of $330 million in customer refunds for 2018 and 2019 and the deferral of certain revenues and tax benefits to be addressed in the Georgia Power 2019 Base Rate Case. The Georgia PSC also approved an increase to Georgia Power's retail equity ratio to address some of the negative cash flow and credit metric impacts of the Tax Reform Legislation. See FUTURE EARNINGS POTENTIAL – "Retail Regulatory Matters – Rate Plans" herein for additional information on the Georgia Power Tax Reform Settlement Agreement.

Georgia Power 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. Georgia Power'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 Georgia Power's results and generally targets the top quartile of these surveys in measuring performance.

See RESULTS OF OPERATIONS herein for information on Georgia Power's financial performance.

Plant Vogtle Units 3 and 4 Status

In 2009, the Georgia PSC certified construction of Plant Vogtle Units 3 and 4 (with electric generating capacity of approximately 1,100 MWs each). Georgia Power holds a 45.7% ownership interest in Plant Vogtle Units 3 and 4. In March 2017, the EPC Contractor filed for bankruptcy protection under Chapter 11 of the U.S. Bankruptcy Code. In December 2017, the Georgia PSC approved Georgia Power's recommendation to continue construction. The current expected in-service dates remain November 2021 for Unit 3 and November 2022 for Unit 4.

In the second quarter 2018, Georgia Power revised its base capital cost forecast and estimated contingency to complete construction and start-up of Plant Vogtle Units 3 and 4 to $8.0 billion and $0.4 billion, respectively, for a total project capital cost forecast of $8.4 billion (net of $1.7 billion received under the Guarantee Settlement Agreement and approximately $188 million in related Customer Refunds), with respect to Georgia Power's ownership interest. Although Georgia Power believes these incremental costs are reasonable and necessary to complete the project and the Georgia PSC's order in the seventeenth VCM proceeding specifically states that the construction of Plant Vogtle Units 3 and 4 is not subject to a cost cap, Georgia Power did not seek rate recovery for the $0.7 billion increase in costs included in the current base capital cost forecast (or any related financing costs) in the nineteenth VCM report that was approved by the Georgia PSC on February 19, 2019. In connection with future VCM filings, Georgia Power may request the Georgia PSC to evaluate costs currently included in the construction contingency estimate for rate recovery as and when they are appropriately included in the base capital cost forecast. After considering the significant level of uncertainty that exists regarding the future recoverability of costs included in the construction contingency estimate since the ultimate outcome of these matters is subject to the outcome of future assessments by management, as well as Georgia PSC decisions in these future regulatory proceedings, Georgia Power recorded a total pre-tax charge to income of $1.1 billion ($0.8 billion after tax) in the second quarter 2018.

As a result of the increase in the total project capital cost forecast and Georgia Power's decision not to seek rate recovery of the increase in the base capital costs, the holders of at least 90% of the ownership interests in Plant Vogtle Units 3 and 4 were required to vote to continue construction. On September 26, 2018, the Vogtle Owners unanimously voted to continue construction of Plant Vogtle Units 3 and 4. In connection with the vote to continue construction, Georgia Power entered into (i) a binding term sheet (Vogtle Owner Term Sheet) with the other Vogtle Owners and certain of MEAG's wholly-owned subsidiaries, including MEAG Power SPVJ, LLC (MEAG SPVJ), to take certain actions which partially mitigate potential financial exposure for the other Vogtle Owners and (ii) a term sheet (MEAG Term Sheet) with MEAG and MEAG SPVJ to provide funding with respect to MEAG

SPVJ's ownership interest in Plant Vogtle Units 3 and 4 under certain circumstances. On January 14, 2019, Georgia Power, MEAG, and MEAG SPVJ entered into an agreement to implement the provisions of the MEAG Term Sheet. On February 18, 2019, Georgia Power, the other Vogtle Owners, and certain of MEAG's wholly-owned subsidiaries entered into certain amendments to their joint ownership agreements to implement the provisions of the Vogtle Owner Term Sheet.

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

See FUTURE EARNINGS POTENTIAL – "Retail Regulatory Matters – Nuclear Construction" herein for additional information on Plant Vogtle Units 3 and 4.

Earnings

Georgia Power's 2018 net income after dividends on preferred and preference stock was $0.8 billion, representing a $621 million, or 43.9%, decrease from the previous year. The decrease was due primarily to a $1.1 billion ($0.8 billion after tax) charge in the second quarter 2018 for an estimated probable loss related to Georgia Power's construction of Plant Vogtle Units 3 and 4, revenues deferred as a regulatory liability for customer bill credits related to the Tax Reform Legislation, an adjustment for an expected refund to retail customers as a result of Georgia Power's retail ROE exceeding the allowed retail ROE range under the 2013 ARP in 2018, and higher non-fuel operations and maintenance expenses. Partially offsetting the decrease were lower federal income tax expense as a result of the Tax Reform Legislation and an increase in retail revenues associated with colder weather in the first quarter 2018 and warmer weather in the second and third quarters 2018 compared to the corresponding periods in 2017.

Georgia Power's 2017 net income after dividends on preferred and preference stock was $1.4 billion, representing an $84 million, or 6.3%, increase from 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.

RESULTS OF OPERATIONS

A condensed income statement for Georgia Power follows:

	Amount	Increase (Decrease) from Prior Year	
	2018	**2018**	2017
		(in millions)	
Operating revenues	**$ 8,420**	**$ 110**	$ (73)
Fuel	**1,698**	**27**	(136)
Purchased power	**1,153**	**115**	159
Other operations and maintenance	**1,860**	**136**	(279)
Depreciation and amortization	**923**	**28**	40
Taxes other than income taxes	**437**	**28**	4
Estimated loss on Plant Vogtle Units 3 and 4	**1,060**	**1,060**	—
Total operating expenses	**7,131**	**1,394**	(212)
Operating income	**1,289**	**(1,284)**	139
Interest expense, net of amounts capitalized	**397**	**(22)**	31
Other income (expense), net	**115**	**11**	23
Income taxes	**214**	**(616)**	50
Net income	**793**	**(635)**	81
Dividends on preferred and preference stock	**—**	**(14)**	(3)
Net income after dividends on preferred and preference stock	**$ 793**	**$ (621)**	$ 84

Operating Revenues

Operating revenues for 2018 were $8.4 billion, reflecting a $110 million increase from 2017. Details of operating revenues were as follows:

	2018	2017
	(in millions)	
Retail — prior year	**$ 7,738**	$ 7,772
Estimated change resulting from —		
Rates and pricing	**(363)**	114
Sales growth (decline)	**92**	(33)
Weather	**131**	(166)
Fuel cost recovery	**154**	51
Retail — current year	**7,752**	7,738
Wholesale revenues —		
Non-affiliates	**163**	163
Affiliates	**24**	26
Total wholesale revenues	**187**	189
Other operating revenues	**481**	383
Total operating revenues	**$ 8,420**	$ 8,310
Percent change	**1.3%**	(0.9)%

Retail revenues of $7.8 billion in 2018 increased $14 million, or 0.2%, compared to 2017. The significant factors driving this change are shown in the preceding table. The decrease in rates and pricing was primarily due to revenues deferred as a regulatory liability for customer bill credits related to the Tax Reform Legislation and an adjustment for an expected refund to retail customers as a result of Georgia Power's retail ROE exceeding the allowed retail ROE range under the 2013 ARP in 2018. See Note 2 to the financial statements under "Georgia Power – Rate Plans" for additional information.

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. See Note 2 to the financial statements under "Georgia Power – Nuclear Construction – Regulatory Matters" for additional information on the NCCR tariff.

See "Energy Sales" below for a discussion of changes in the volume of energy sold, including changes related to sales growth (decline) and weather.

Electric rates include provisions to adjust billings for fluctuations in fuel costs, including the energy component of purchased power costs. Under these fuel cost recovery provisions, fuel revenues generally equal fuel expenses and do not affect net income. See FUTURE EARNINGS POTENTIAL – "Retail Regulatory Matters – Fuel Cost Recovery" herein for additional information.

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

	2018	2017	2016
		(in millions)	
Capacity and other	**$ 54**	$ 67	$ 72
Energy	**109**	96	103
Total non-affiliated	**$ 163**	$ 163	$ 175

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 Georgia Power's and the Southern Company system's generation, demand for energy within the Southern Company system's electric service territory, and the availability of the Southern Company system's generation. Increases and decreases in energy revenues that are driven by fuel prices are accompanied by an increase or decrease in fuel costs and do not have a significant

impact on net income. Short-term opportunity sales are made at market-based rates that generally provide a margin above Georgia Power's variable cost of energy.

Wholesale revenues from non-affiliated sales remained flat in 2018 as compared to 2017. Capacity revenues decreased $13 million, offset by a $13 million increase in energy revenues. The decrease in capacity revenues was primarily due to the expiration of a wholesale contract in the fourth quarter 2017. The increase in energy revenues was primarily due to increased demand, partially offset by the effects of expired contracts. Wholesale revenues from non-affiliated sales decreased $12 million, or 6.9%, in 2017 as compared to 2016. The decrease was related to decreases of $5 million in capacity revenues and $7 million in energy revenues. The decrease in capacity revenues reflects the expiration of wholesale contracts in the first and second quarters of 2016. The decrease in energy revenues was primarily due to lower demand and the effects of the expired contracts.

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 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 2018, wholesale revenues from sales to affiliates decreased $2 million as compared to 2017. 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 Georgia Power-owned generation.

Other operating revenues increased $98 million, or 25.6%, in 2018 from the prior year largely due to $94 million of revenues primarily from unregulated sales of products and services that were reclassified as other revenues as a result of the adoption of ASC 606, *Revenue from Contracts with Customers* (ASC 606). In prior periods, these revenues were included in other income (expense), net. See Note 1 to the financial statements for additional information regarding Georgia Power's adoption of ASC 606.

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.

Energy Sales

Changes in revenues are influenced heavily by the change in the volume of energy sold from year to year. KWH sales for 2018 and the percent change from the prior year were as follows:

	Total KWHs	**Total KWH Percent Change**		**Weather-Adjusted Percent Change**	
	2018	**2018**	2017	**2018**	2017
	(in billions)				
Residential	**28.3**	**8.4%**	(5.2)%	**2.6%**	(0.2)%
Commercial	**33.0**	**2.5**	(2.4)	**1.6**	(0.9)
Industrial	**23.7**	**0.6**	(1.0)	**0.2**	(0.1)
Other	**0.5**	**(6.0)**	(4.2)	**(6.3)**	(4.0)
Total retail	**85.5**	**3.8**	(2.9)	**1.5%**	(0.4)%
Wholesale					
Non-affiliates	**3.2**	**(4.2)**	(4.0)		
Affiliates	**0.5**	**(34.2)**	(42.8)		
Total wholesale	**3.7**	**(10.1)**	(15.3)		
Total energy sales	**89.2**	**3.1%**	(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.

In 2018, KWH sales for the residential class increased 8.4% compared to 2017 primarily due to colder weather in the first quarter 2018 and warmer weather in the second and third quarters 2018 compared to the corresponding periods in 2017. Weather-adjusted residential KWH sales and weather-adjusted commercial KWH sales increased by 2.6% and 1.6%, respectively, largely due to customer growth. Weather-adjusted industrial KWH sales were essentially flat primarily due to increased demand in the primary and fabricated metal sectors, offset by decreased demand in the textiles and stone, clay, and glass sectors. Additionally, customer usage for all customer classes increased due to the negative impacts of Hurricane Irma in 2017.

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 in 2017.

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 Georgia Power. The mix of fuel sources for the generation of electricity is determined primarily by demand, the unit cost of fuel consumed, and the availability of generating units. Additionally, Georgia Power purchases a portion of its electricity needs from the wholesale market.

Details of Georgia Power's generation and purchased power were as follows:

	2018	2017	2016
Total generation *(in billions of KWHs)*	**65.2**	63.2	68.4
Total purchased power *(in billions of KWHs)*	**27.9**	26.9	24.8
Sources of generation *(percent)* —			
Gas	**42**	41	38
Coal	**30**	32	36
Nuclear	**25**	25	24
Hydro	**3**	2	2
Cost of fuel, generated *(in cents per net KWH)* —			
Gas	**2.75**	2.68	2.36
Coal	**3.21**	3.17	3.28
Nuclear	**0.82**	0.83	0.85
Average cost of fuel, generated *(in cents per net KWH)*	**2.40**	2.36	2.33
Average cost of purchased power *(in cents per net KWH)*(*)	**4.79**	4.62	4.53

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

Fuel and purchased power expenses were $2.9 billion in 2018, an increase of $142 million, or 5.2%, compared to 2017. The increase was primarily due to a $74 million increase in the average cost of fuel and purchased power primarily related to higher natural gas and energy prices and an increase of $68 million related to the volume of KWHs generated and purchased primarily due to colder weather in the first quarter 2018 and warmer weather in the second and third quarters 2018 compared to the corresponding periods in 2017.

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 energy transactions do not have a significant impact on earnings since these fuel expenses are generally offset by fuel revenues through Georgia Power'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 2018, an increase of $27 million, or 1.6%, compared to 2017. The increase was primarily due to an increase of 2.6% in the average cost of natural gas per KWH generated and an increase of 1.9% in the volume of KWHs generated largely due to colder weather in the first quarter 2018 and warmer weather in the second and third quarters 2018 compared to the corresponding periods in 2017. 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.

Purchased Power - Non-Affiliates

Purchased power expense from non-affiliates was $430 million in 2018, an increase of $14 million, or 3.4%, compared to 2017. The increase was primarily due to an 8.5% increase in the average cost per KWH purchased primarily due to higher energy prices, partially offset by a decrease of 3.8% in volume of KWHs purchased primarily due to the higher market cost of available energy as compared to Southern Company system resources. 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 Georgia Power-owned generating units.

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 $723 million in 2018, an increase of $101 million, or 16.2%, compared to 2017. The increase was primarily due to a 6.3% increase in the volume of KWHs purchased due to colder weather in the first quarter 2018 and scheduled generation outages and warmer weather in the second and third quarters 2018 and a 3.0% increase in the average cost per KWH purchased primarily resulting from higher energy prices. 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 Georgia Power-owned generating units and a 1.8% increase in the average cost per KWH purchased primarily resulting from higher natural gas prices.

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 2018, other operations and maintenance expenses increased $136 million, or 7.9%, compared to 2017. The increase was primarily due to $88 million of expenses from unregulated sales of products and services that were reclassified to other operations and maintenance expenses as a result of the adoption of ASC 606. In prior periods, these expenses were included in other income (expense), net. Also contributing to the increase were a $39 million decrease in gains on sales of assets and a $28 million increase in transmission and distribution overhead line maintenance, primarily related to additional vegetation management, partially offset by a decrease of $18 million associated with an employee attrition plan in 2017. See Note 1 to the financial statements for additional information regarding Georgia Power's adoption of ASC 606.

In 2017, other operations and maintenance expenses decreased $279 million, or 13.9%, 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, $46 million in transmission and distribution overhead line maintenance, $22 million in employee benefits, and $22 million in customer accounts and sales costs. Other factors include a $40 million increase in gains on 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.

Depreciation and Amortization

Depreciation and amortization increased $28 million, or 3.1%, in 2018 compared to 2017. The increase was primarily due to additional plant in service.

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 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.

See Note 5 to the financial statements under "Depreciation and Amortization" for additional information.

Taxes Other Than Income Taxes

In 2018, taxes other than income taxes increased $28 million, or 6.8%, compared to 2017 primarily due to increases of $19 million in property taxes as a result of an increase in the assessed value of property and $11 million in municipal franchise fees largely related to higher retail revenues. In 2017, taxes other than income taxes increased $4 million, or 1.0%, compared to 2016.

Estimated Loss on Plant Vogtle Units 3 and 4

In the second quarter 2018, an estimated probable loss of $1.1 billion was recorded to reflect Georgia Power's revised estimate to complete construction and start-up of Plant Vogtle Units 3 and 4, which reflects the increase in costs included in the revised base capital cost forecast for which Georgia Power did not seek rate recovery and costs included in the revised construction contingency estimate for which Georgia Power may seek rate recovery as and when such costs are appropriately included in the base capital cost forecast. See Note 2 to the financial statements under "Georgia Power – Nuclear Construction" for additional information.

Interest Expense, Net of Amounts Capitalized

In 2018, interest expense, net of amounts capitalized decreased $22 million, or 5.3%, compared to 2017 and increased $31 million, or 8.0%, compared to 2016 primarily due to changes in outstanding borrowings.

Other Income (Expense), Net

In 2018, other income (expense), net increased $11 million compared to the prior year primarily due to an increase in AFUDC equity of $29 million resulting from a higher AFUDC rate due to a higher equity ratio and lower short-term borrowings, partially offset by a decrease of $21 million associated with revenues and expenses, net primarily from unregulated sales of products and services. In 2018, these revenues and expenses are included in other revenues and other operations and maintenance expenses, respectively, as a result of the adoption of ASC 606. See Note 1 to the financial statements for additional information regarding Georgia Power's adoption of ASC 606.

In 2017, other income (expense), net increased $23 million compared to the prior year primarily due to a $28 million decrease in the non-service cost components of net periodic pension and other postretirement benefit costs, a $7 million increase in third party infrastructure services revenue, and a $6 million increase in wholesale operating fee revenue associated with contractual targets, partially offset by a $10 million increase in charitable donations and an $8 million decrease in AFUDC equity resulting from higher short-term borrowings. See Notes 1 under "Recently Adopted Accounting Standards" and 11 to the financial statements for additional information on Georgia Power's net periodic pension and other postretirement benefit costs.

Income Taxes

Income taxes decreased $616 million, or 74.2%, in 2018 compared to the prior year primarily due to a lower federal income tax rate as a result of the Tax Reform Legislation and the reduction in pre-tax earnings resulting from the estimated probable loss related to Plant Vogtle Units 3 and 4.

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 the Tax Reform Legislation.

See Note 10 to the financial statements for additional information.

Dividends on Preferred and Preference Stock

Dividends on preferred and preference stock decreased $14 million, or 100.0%, in 2018 compared to 2017 and decreased $3 million, or 17.6%, in 2017 compared to 2016. The decreases were due to the redemption in October 2017 of all outstanding shares of Georgia Power's preferred and preference stock. See Note 8 to the financial statements under "Outstanding Classes of Capital Stock – Georgia Power" for additional information.

Effects of Inflation

Georgia Power 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 Georgia Power's results of operations has not been substantial in recent years.

FUTURE EARNINGS POTENTIAL

General

Georgia Power 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 Georgia Power to retail customers are set by the Georgia 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 ACCOUNTING POLICIES – "Application of Critical Accounting Policies and Estimates – Utility Regulation" herein and Note 2 to the financial statements under "Georgia Power" 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 Georgia Power's future earnings depends on numerous factors that affect the opportunities, challenges, and risks of Georgia Power's business of providing electric service. These factors include Georgia Power'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, continued customer growth, and the weak pace of growth in electricity use per customer, especially in residential and commercial markets. Plant Vogtle Units 3 and 4 construction and rate recovery are also major factors. 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 more 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 Georgia Power'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.

Environmental Matters

Georgia Power'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. Georgia Power maintains comprehensive environmental compliance and GHG strategies to assess upcoming requirements and compliance costs associated with these environmental laws and regulations. The costs, including capital expenditures, operations and maintenance costs, and costs reflected in ARO liabilities, required to comply with environmental laws and regulations and to achieve stated goals may impact future electric generating unit retirement and replacement decisions, results of operations, cash flows, and/or financial condition. Related costs may result from the installation of additional environmental controls, closure and monitoring of CCR facilities, unit retirements, or changing fuel sources for certain existing units, as well as related upgrades to Georgia Power's transmission and distribution systems. A major portion of these costs is expected to be recovered through retail rates. The ultimate impact of environmental laws and regulations and the GHG goals discussed herein will depend on various factors, such as state adoption and implementation of requirements, the availability and cost of any deployed technology, fuel prices, and the outcome of pending and/or future legal challenges.

New or revised environmental laws and regulations could affect many areas of Georgia Power'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 recovered in rates on a timely basis. Georgia Power'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/or 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 2018, Georgia Power has invested approximately $6.0 billion in environmental capital retrofit projects to comply with environmental requirements, with annual totals of approximately $0.5 billion, $0.3 billion, and $0.2 billion for 2018, 2017, and 2016, 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, Georgia Power's current compliance strategy estimates capital expenditures of $0.7 billion from 2019 through 2023, with annual totals of approximately $0.2 billion, $0.1 billion, $0.1 billion, $0.2 billion, and $0.1 billion for 2019, 2020, 2021, 2022, and 2023, respectively. These estimates do not include any potential compliance costs associated with pending regulation of CO_2 emissions from fossil fuel-fired electric generating units. See "Global Climate Issues" herein for additional information. Georgia Power also anticipates substantial expenditures associated with ash pond closure and ground water monitoring under the CCR Rule, which

are reflected in Georgia Power's ARO liabilities. See FINANCIAL CONDITION AND LIQUIDITY – "Capital Requirements and Contractual Obligations" herein and Note 6 to the financial statements 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) to protect and improve the nation's air quality, which it reviews and revises periodically. Following a NAAQS revision, states are required to develop an EPA-approved plan to protect air quality. These state plans 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 electric generating facilities. All areas within Georgia Power's service territory have been designated as attainment for all NAAQS except for a seven-county area within metropolitan Atlanta that is not in attainment with the 2015 ozone NAAQS and the area surrounding Plant Hammond, which will not be designated attainment or nonattainment for the 2010 SO_2 standard until December 2020. If areas are designated as nonattainment in the future, increased compliance costs could result. See "Retail Regulatory Matters – Integrated Resource Plan" herein for information regarding Georgia Power's request to decertify and retire Plant Hammond.

In 2011, the EPA finalized the Cross-State Air Pollution Rule (CSAPR) to address impacts of SO_2 and NO_X emissions from fossil fuel-fired electric generating plants. CSAPR establishes emissions trading programs and budgets for certain states and allocates emissions allowances for sources in those states. In 2016, the EPA published a final rule establishing more stringent ozone season NO_X emissions budgets in Alabama. Georgia's ozone season NO_X emissions budget remained unchanged. Increases in either future fossil fuel-fired generation or the availability or cost of CSAPR allowances could have a negative financial impact on results of operations for Georgia Power.

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 demonstrating continued reasonable progress towards achieving visibility improvement goals. The EPA has approved the regional progress SIP for 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 (CWIS) to minimize their effects on fish and other aquatic life at existing power plants (e.g. coal, natural gas, oil, and nuclear generating plants) and manufacturing facilities. The regulation requires plant-specific studies to determine applicable CWIS changes to protect organisms that either get caught on the intake screens (impingement) or are drawn into the cooling system (entrainment). Georgia Power is conducting these studies and currently anticipates applicable CWIS changes may include fish-friendly CWIS screens with fish return systems and minor additions of monitoring equipment at certain plants. However, the ultimate impact of this rule will depend on the outcome of these plant-specific studies, any additional protective measures required to be incorporated into each plant's National Pollutant Discharge Elimination System (NPDES) permit based on site-specific factors, and the outcome of any legal challenges.

In 2015, the EPA finalized the steam electric effluent limitations guidelines (ELG) rule (2015 ELG Rule) that set national standards for wastewater discharges from new and existing steam electric generating units generating greater than 50 MWs. The 2015 ELG Rule prohibits effluent discharges of certain waste streams and imposes stringent limits on flue gas desulfurization (scrubber) wastewater discharges. The revised technology-based limits and the CCR Rule require extensive changes to existing ash and wastewater management systems or the installation and operation of new ash and wastewater management systems. Compliance with the 2015 ELG Rule is expected to require capital expenditures and increased operational costs primarily for Georgia Power's coal-fired electric generation. State environmental agencies will incorporate specific compliance applicability dates in the NPDES permitting process for each ELG waste stream no later than December 31, 2023. The EPA is scheduled to issue a new rulemaking by December 2019 that could revise the limitations and applicability dates of two of the waste streams regulated in the 2015 ELG Rule. The impact of any changes to the 2015 ELG Rule will depend on the content of the new rule and the outcome of any legal challenges.

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, canals, and wastewater treatment ponds), which could impact new generation projects and permitting and reporting requirements associated with the installation, expansion, and maintenance of transmission and distribution projects. The EPA and the Corps are expected to publish a final rule in 2019 to replace the 2015

WOTUS definition. The impact of any changes to the 2015 WOTUS rule will depend on the content of this final rule and the outcome of any legal challenges.

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 (ash ponds) at active generating power plants. In addition to the EPA's CCR Rule, the State of Georgia has also finalized its own regulations regarding the handling of CCR. The EPA's CCR Rule requires landfills and ash ponds to be evaluated against a set of performance criteria and potentially closed if minimum criteria are not met. Closure of existing landfills and ash ponds could require installation of equipment and infrastructure to manage CCR in accordance with the CCR Rule. Based on cost estimates for closure and monitoring of landfills and ash ponds pursuant to the CCR Rule, Georgia Power recorded an update to the AROs for each CCR unit in 2015. As further analysis is performed and closure details are developed, Georgia Power has continued to periodically update these cost estimates, as discussed further below.

The EPA published certain amendments to the CCR Rule, which became effective August 29, 2018. These amendments extend the date from April 2019 to October 31, 2020 to cease sending CCR and other waste streams to ash ponds that demonstrate compliance with all except two of the specified performance criteria. However, the Georgia Department of Natural Resources has not incorporated these amendments into its state CCR rule.

On August 21, 2018, the U.S. Court of Appeals for the District of Columbia Circuit issued a decision suggesting the EPA should regulate previously-excluded inactive ash ponds located at retired generation facilities and questioning both the ability of unlined ash ponds to continue operating no matter the performance criteria results and the classification of clay-lined landfills and ash ponds. These developments could impact the expected timing of Georgia Power's landfill and ash pond closure activities, but the extent of any impact will depend on the outcome of ongoing litigation, anticipated EPA rulemaking action to establish further guidance, and the outcome of any legal challenges.

In December 2018, Georgia Power recorded an increase of approximately $3.1 billion to its AROs related to the CCR Rule and the related state rule. During the second half of 2018, Georgia Power completed a strategic assessment related to its plans to close the ash ponds at all of its generating plants in compliance with the CCR Rule and the related state rule. This assessment included engineering and constructability studies related to design assumptions for ash pond closures and advanced engineering methods. The results indicated that additional closure costs will be required to close these ash ponds, primarily due to changes in closure strategies, the estimated amount of ash to be excavated, and additional water management requirements necessary to support closure strategies. These factors also impact the estimated timing of future cash outlays.

Georgia Power expects to periodically update its ARO cost estimates. Absent continued recovery of ARO costs through regulated rates, Georgia Power's results of operations, cash flows, and financial condition could be materially impacted. See "Retail Regulatory Matters – Integrated Resource Plan" and FINANCIAL CONDITION AND LIQUIDITY – "Capital Requirements and Contractual Obligations" herein and Note 6 to the financial statements for additional information.

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

Nuclear Decommissioning

In December 2018, Georgia Power completed updated decommissioning cost site studies for Plant Hatch and Plant Vogtle Units 1 and 2. The estimated cost of decommissioning based on the studies resulted in an increase in Georgia Power's ARO liability of approximately $130 million. Georgia Power currently collects $4 million and $2 million annually in rates, which is used to fund external nuclear decommissioning trusts for Plant Hatch and Plant Vogtle Units 1 and 2, respectively. Georgia Power expects the Georgia PSC to review and adjust, if necessary, these amounts in the Georgia Power 2019 Base Rate Case. See Note 6 to the financial statements for additional information.

Environmental Remediation

Georgia Power 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, Georgia Power may also incur substantial costs to clean up affected sites. Georgia Power 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. Georgia Power has received authority from the Georgia PSC to recover approved environmental compliance costs through regulatory mechanisms. Georgia Power 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 Remediation" for additional information.

Global Climate Issues

On August 31, 2018, the EPA published a proposed rule known as the Affordable Clean Energy (ACE) Rule, which is intended to replace a regulation enacted in 2015 known as the Clean Power Plan (CPP), that would limit CO_2 emissions from existing fossil fuel-fired electric generating units. The CPP has been stayed by the U.S. Supreme Court since 2016. The ACE Rule would require states to develop GHG unit-specific emission rate standards based on heat-rate efficiency improvements for existing fossil fuel-fired steam units. As proposed, combustion turbines, including natural gas combined cycles, are not affected sources. As of January 1, 2019, Georgia Power has ownership interests in 20 fossil fuel-fired steam units to which the proposed ACE Rule is applicable. The ultimate impact of this rule to Georgia Power is currently unknown and will depend on changes between the proposal and the final rule, subsequent state plan developments and requirements, and any associated legal challenges.

On December 20, 2018, the EPA published a proposed review of the Standards of Performance for Greenhouse Gas Emissions from New, Modified, and Reconstructed Stationary Sources: Electric Utility Generating Units final rule (2015 NSPS rule). The EPA's final 2015 NSPS rule set standards of performance for new, modified, and reconstructed electric utility generating units which included stationary combustion turbines and fossil-fired steam boilers. This proposal reduces the stringency of the 2015 NSPS rule by not basing the new and reconstructed fossil-fired steam boiler and IGCC standards on partial carbon capture and sequestration. The impact of any changes to this rule will depend on the content of the final rule and the outcome of any legal challenges.

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, Georgia Power's 2017 GHG emissions were approximately 30 million metric tons of CO_2 equivalent. The preliminary estimate of Georgia Power's 2018 GHG emissions on the same basis is approximately 30 million metric tons of CO_2 equivalent.

Through 2017, the Southern Company system has achieved an estimated GHG emission reduction of 36% since 2007. In April 2018, Southern Company established an intermediate goal of a 50% reduction in carbon emissions from 2007 levels by 2030 and a long-term goal of low- to no-carbon operations by 2050. To achieve these goals, the Southern Company system expects to continue growing its renewable energy portfolio, optimize technology advancements to modernize its transmission and distribution systems, increase the use of natural gas for generation, complete ongoing construction projects, including Georgia Power's interest in Plant Vogtle Units 3 and 4, invest in energy efficiency, and continue research and development efforts focused on technologies to lower GHG emissions. The Southern Company system's ability to achieve these goals also will be dependent on many external factors, including supportive national energy policies, low natural gas prices, and the development, deployment, and advancement of relevant energy technologies.

FERC Matters

On May 10, 2018, AMEA and Cooperative Energy filed with the FERC a complaint against SCS and the traditional electric operating companies (including Georgia Power) claiming that the current 11.25% base ROE used in calculating the annual transmission revenue requirements of the traditional electric operating companies' (including Georgia Power's) open access transmission tariff is unjust and unreasonable as measured by the applicable FERC standards. The complaint requested that the base ROE be set no higher than 8.65% and that the FERC order refunds for the difference in revenue requirements that results from applying a just and reasonable ROE established in this proceeding upon determining the current ROE is unjust and unreasonable. On June 18, 2018, SCS and the traditional electric operating companies (including Georgia Power) filed their response challenging the adequacy of the showing presented by the complainants and offering support for the current ROE. On September 6, 2018, the FERC issued an order establishing a refund effective date of May 10, 2018 in the event a refund is due and initiating an investigation and settlement procedures regarding the current base ROE. Through December 31, 2018, the estimated maximum potential refund is not expected to be material to Georgia Power's results of operations or cash flows. The ultimate outcome of this matter cannot be determined at this time.

Retail Regulatory Matters

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, ECCR tariffs, and Municipal Franchise Fee (MFF) tariffs. Georgia Power is scheduled to file a base rate case by July 1, 2019, which may continue or modify these tariffs. In addition, financing costs on certified construction costs 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 2 to the financial statements under "Georgia Power – Rate Plans," " – Fuel Cost Recovery," and " – Nuclear Construction" for additional information.

On November 16, 2018, Georgia Power completed the sale of its natural gas lateral pipeline serving Plant McDonough Units 4 through 6 to SNG at net book value, as approved by the Georgia PSC on January 16, 2018. Georgia Power expects payment of $142 million from SNG to occur in the first quarter 2020. During the interim period, Georgia Power will receive a discounted shipping rate to reflect the delayed consideration. Southern Company Gas, an affiliate of Georgia Power, owns a 50% equity interest in SNG.

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 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 will retain its merger savings, net of transition costs, as defined in the settlement agreement; through December 31, 2022, such net merger savings will be shared on a 60/40 basis with customers; thereafter, all merger savings will be retained by customers.

There were no changes to Georgia Power's traditional base tariff rates, ECCR tariff, DSM tariffs, or MFF tariff in 2017 or 2018.

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 2016, Georgia Power's retail ROE exceeded 12.00%, and Georgia Power refunded to retail customers in 2018 approximately $40 million as approved by the Georgia PSC. On February 5, 2019, the Georgia PSC approved a settlement between Georgia Power and the staff of the Georgia PSC under which Georgia Power's retail ROE for 2017 was stipulated to exceed 12.00% and Georgia Power will reduce certain regulatory assets by approximately $4 million in lieu of providing refunds to retail customers. In 2018, Georgia Power's retail ROE exceeded 12.00%, and Georgia Power accrued approximately $100 million to refund to retail customers, subject to review and approval by the Georgia PSC.

On April 3, 2018, the Georgia PSC approved the Georgia Power Tax Reform Settlement Agreement. Pursuant to the Georgia Power Tax Reform Settlement Agreement, to reflect the federal income tax rate reduction impact of the Tax Reform Legislation, Georgia Power will refund to customers a total of $330 million through bill credits. Georgia Power issued bill credits of approximately $130 million in 2018 and will issue bill credits of approximately $95 million in June 2019 and $105 million in February 2020. In addition, Georgia Power is deferring as a regulatory liability (i) the revenue equivalent of the tax expense reduction resulting from legislation lowering the Georgia state income tax rate from 6.00% to 5.75% in 2019 and (ii) the entire benefit of federal and state excess accumulated deferred income taxes, which is expected to total approximately $700 million at December 31, 2019. At December 31, 2018, the related regulatory liability balance totaled $610 million. The amortization of these regulatory liabilities is expected to be addressed in the Georgia Power 2019 Base Rate Case. If there is not a base rate case in 2019, customers will receive $185 million in annual bill credits beginning in 2020, with any additional federal and state income tax savings deferred as a regulatory liability, until Georgia Power's next base rate case.

To address some of the negative cash flow and credit quality impacts of the Tax Reform Legislation, the Georgia PSC also approved an increase in Georgia Power's retail equity ratio to the lower of (i) Georgia Power's actual common equity weight in its capital structure or (ii) 55%, until the Georgia Power 2019 Base Rate Case. At December 31, 2018, Georgia Power's actual retail common equity ratio (on a 13-month average basis) was approximately 55%. Benefits from reduced federal income tax rates in excess of the amounts refunded to customers will be retained by Georgia Power to cover the carrying costs of the incremental equity in 2018 and 2019.

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 2016, the Georgia PSC approved Georgia Power's triennial Integrated Resource Plan (2016 IRP) including 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 Georgia Power 2019 Base Rate Case.

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. In March 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 the Georgia Power 2019 Base Rate Case.

On January 31, 2019, Georgia Power filed its triennial IRP (2019 IRP). The filing includes a request to decertify and retire Plant Hammond Units 1 through 4 (840 MWs) and Plant McIntosh Unit 1 (142.5 MWs) upon approval of the 2019 IRP.

In the 2019 IRP, Georgia Power requested approval to reclassify the remaining net book value of Plant Hammond Units 1 through 4 (approximately $520 million at December 31, 2018) upon retirement to a regulatory asset to be amortized ratably over a period equal to the applicable unit's remaining useful life through 2035. For Plant McIntosh Unit 1, Georgia Power requested approval to reclassify the remaining net book value (approximately $40 million at December 31, 2018) upon retirement to a regulatory asset to be amortized over a three-year period to be determined in the Georgia Power 2019 Base Rate Case. Georgia Power also requested approval to reclassify any unusable material and supplies inventory balances remaining at the applicable unit's retirement date to a regulatory asset for recovery over a period to be determined in the Georgia Power 2019 Base Rate Case.

The 2019 IRP also includes a request to certify approximately 25 MWs of capacity at Plant Scherer Unit 3 for the retail jurisdiction beginning January 1, 2020, following the expiration of a wholesale PPA.

The 2019 IRP also includes details regarding ARO costs associated with ash pond and landfill closures and post-closure care. Georgia Power requested the timing and rate of recovery of these costs be determined by the Georgia PSC in the Georgia Power 2019 Base Rate Case. See "Environmental Matters – Environmental Laws and Regulations – Coal Combustion Residuals" and FINANCIAL CONDITION AND LIQUIDITY – "Capital Requirements and Contractual Obligations" herein and Note 6 to the financial statements for additional information regarding Georgia Power's AROs.

Georgia Power also requested approval to issue two capacity-based requests for proposals (RFP). If approved, the first capacity-based RFP will seek resources that can provide capacity beginning in 2022 or 2023 and the second capacity-based RFP will seek resources that can provide capacity beginning in 2026, 2027, or 2028. Additionally, the 2019 IRP includes a request to procure an additional 1,000 MWs of renewable resources through a competitive bidding process. Georgia Power also proposed to invest in a portfolio of up to 50 MWs of battery energy storage technologies.

A decision from the Georgia PSC on the 2019 IRP is expected in mid-2019.

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

Fuel Cost Recovery

Georgia Power has established fuel cost recovery rates approved by the Georgia PSC. On August 16, 2018, the Georgia PSC approved the deferral of Georgia Power's next fuel case to no later than March 16, 2020, with new rates, if any, to be effective June 1, 2020. 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 or over recovered fuel balance exceeds $200 million. At December 31, 2018, Georgia Power's under recovered fuel balance was $115 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.

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 Georgia Power's revenues or net income, but will affect operating cash flows.

Storm Damage Recovery

Georgia Power is accruing $30 million annually through December 31, 2019, as provided in the 2013 ARP, for incremental operations and maintenance costs of damage from major storms to its transmission and distribution facilities. At December 31, 2018, the total balance in the regulatory asset related to storm damage was $416 million. During October 2018, Hurricane Michael caused significant damage to Georgia Power's transmission and distribution facilities. The incremental restoration costs related to this hurricane deferred in the regulatory asset for storm damage totaled approximately $115 million. Hurricanes Irma and Matthew also caused significant damage to Georgia Power's transmission and distribution facilities during September 2017 and October 2016, respectively. The incremental restoration costs related to Hurricanes Irma and Matthew deferred in the regulatory asset for storm damage totaled approximately $250 million. The rate of storm damage cost recovery is expected to be adjusted as part of the Georgia Power 2019 Base Rate Case and further adjusted in future regulatory proceedings as necessary. The ultimate outcome of this matter cannot be determined at this time. See Note 2 to the financial statements under "Georgia Power – Storm Damage Recovery" for additional information regarding Georgia Power's storm damage reserve.

Nuclear Construction

In 2009, the Georgia PSC certified construction of Plant Vogtle Units 3 and 4. Georgia Power holds a 45.7% ownership interest in 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. In March 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 in July 2017 when Georgia Power, acting for itself and as agent for the other Vogtle Owners, and the EPC Contractor entered into the Vogtle Services Agreement. Under the Vogtle Services Agreement, Westinghouse provides facility design and engineering services, procurement and technical support, and staff augmentation on a time and materials cost basis. The Vogtle Services Agreement provides that it 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.

In October 2017, Georgia Power, acting for itself and as agent for the other Vogtle Owners, executed the Bechtel Agreement, a cost reimbursable plus fee arrangement, whereby Bechtel is 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.

Cost and Schedule

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

		(in billions)
Base project capital cost forecast[(a)(b)]	$	8.0
Construction contingency estimate		0.4
Total project capital cost forecast[(a)(b)]		8.4
Net investment as of December 31, 2018[(b)]		(4.6)
Remaining estimate to complete[(a)]	**$**	**3.8**

(a) Excludes financing costs expected to be capitalized through AFUDC of approximately $315 million.

(b) Net of $1.7 billion received from Toshiba under the Guarantee Settlement Agreement and approximately $188 million in related 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 $1.9 billion had been incurred through December 31, 2018.

As construction continues, challenges with management of contractors, subcontractors, and vendors; labor productivity, availability, and/or cost escalation; procurement, fabrication, delivery, assembly, and/or installation and testing, including any required engineering changes, of plant systems, structures, and components (some of which are based on new technology that only recently began initial operation in the global nuclear industry at this scale); or other issues could arise and change the projected schedule and estimated cost. Monthly construction production targets required to maintain the current project schedule will continue to increase significantly throughout 2019. To meet these increasing monthly targets, existing craft construction productivity must improve and additional craft laborers must be retained and deployed.

Georgia Power and Southern Nuclear believe it is a leading practice in connection with a construction project of this size and complexity to periodically validate recent construction progress in comparison to the projected schedule and to verify and update quantities of commodities remaining to install, labor productivity, and forecasted staffing needs. This verification process, led by

Southern Nuclear, was underway as of December 31, 2018 and is expected to be completed during the second quarter 2019. Georgia Power currently does not anticipate any material changes to the total estimated project capital cost forecast for Plant Vogtle Units 3 and 4 or the expected in-service dates of November 2021 and November 2022, respectively, resulting from this verification process. However, the ultimate impact on cost and schedule, if any, will not be known until the verification process is completed. Georgia Power is required to report the results and any project impacts to the Georgia PSC by May 15, 2019.

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 ITAAC 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. However, any extension of the project schedule is currently estimated to result in additional base capital costs of approximately $50 million per month, based on Georgia Power's ownership interests, and AFUDC of approximately $12 million per month. While Georgia Power is not precluded from seeking recovery of any future capital cost forecast increase, management will ultimately determine whether or not to seek recovery. Any further changes to the capital cost forecast that are not expected to be recoverable through regulated rates will be required to be charged to income and such charges could be material.

Joint Owner Contracts

In November 2017, the Vogtle Owners entered into an amendment to their joint ownership agreements for Plant Vogtle Units 3 and 4 to provide for, among other conditions, additional Vogtle Owner approval requirements. Effective August 31, 2018, the Vogtle Owners further amended the joint ownership agreements to clarify and provide procedures for certain provisions of the joint ownership agreements related to adverse events that require the vote of the holders of at least 90% of the ownership interests in Plant Vogtle Units 3 and 4 to continue construction (as amended, and together with the November 2017 amendment, the Vogtle Joint Ownership Agreements). 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.

As a result of the increase in the total project capital cost forecast and Georgia Power's decision not to seek rate recovery of the increase in the base capital costs as described below, the holders of at least 90% of the ownership interests in Plant Vogtle Units 3 and 4 were required to vote to continue construction. On September 26, 2018, the Vogtle Owners unanimously voted to continue construction of Plant Vogtle Units 3 and 4.

Amendments to the Vogtle Joint Ownership Agreements

In connection with the vote to continue construction, Georgia Power entered into (i) the Vogtle Owner Term Sheet with the other Vogtle Owners and MEAG's wholly-owned subsidiaries MEAG SPVJ, MEAG Power SPVM, LLC (MEAG SPVM), and MEAG Power SPVP, LLC (MEAG SPVP) to take certain actions which partially mitigate potential financial exposure for the other Vogtle Owners, including additional amendments to the Vogtle Joint Ownership Agreements and the purchase of PTCs from the other Vogtle Owners, and (ii) the MEAG Term Sheet with MEAG and MEAG SPVJ to provide funding with respect to MEAG SPVJ's ownership interest in Plant Vogtle Units 3 and 4 (Project J) under certain circumstances. On January 14, 2019, Georgia Power, MEAG, and MEAG SPVJ entered into an agreement to implement the provisions of the MEAG Term Sheet (MEAG Funding Agreement). On February 18, 2019, Georgia Power, the other Vogtle Owners, and MEAG's wholly-owned subsidiaries MEAG SPVJ, MEAG SPVM, and MEAG SPVP entered into certain amendments to the Vogtle Joint Ownership Agreements to implement the provisions of the Vogtle Owner Term Sheet (Global Amendments).

Pursuant to the Global Amendments, and consistent with the Vogtle Owner Term Sheet, the Vogtle Joint Ownership Agreements were modified as follows: (i) each Vogtle Owner must pay its proportionate share of qualifying construction costs for Plant Vogtle Units 3 and 4 based on its ownership percentage up to the estimated cost at completion (EAC) for Plant Vogtle Units 3 and 4 which formed the basis of Georgia Power's forecast of $8.4 billion in the nineteenth VCM plus $800 million; (ii) Georgia Power will be responsible for 55.7% of actual qualifying construction costs between $800 million and $1.6 billion over the EAC in the nineteenth VCM (resulting in $80 million of potential additional costs to Georgia Power), with the remaining Vogtle Owners responsible for 44.3% of such costs pro rata in accordance with their respective ownership interests; and (iii) Georgia Power will be responsible for 65.7% of qualifying construction costs between $1.6 billion and $2.1 billion over the EAC in the nineteenth

VCM (resulting in a further $100 million of potential additional costs to Georgia Power), with the remaining Vogtle Owners responsible for 34.3% of such costs pro rata in accordance with their respective ownership interests.

If the EAC is revised and exceeds the EAC in the nineteenth VCM by more than $2.1 billion, each of the other Vogtle Owners will have a one-time option at the time the project budget forecast is so revised to tender a portion of its ownership interest to Georgia Power in exchange for Georgia Power's agreement to pay 100% of such Vogtle Owner's remaining share of total construction costs in excess of the EAC in the nineteenth VCM plus $2.1 billion. In this event, Georgia Power will have the option of cancelling the project in lieu of purchasing a portion of the ownership interest of any other Vogtle Owner. If Georgia Power accepts the offer to purchase a portion of another Vogtle Owner's ownership interest in Plant Vogtle Units 3 and 4, the ownership interest(s) to be conveyed from the tendering Vogtle Owner(s) to Georgia Power will be calculated based on the proportion of the cumulative amount of construction costs paid by each such tendering Vogtle Owner(s) and by Georgia Power as of the COD of Plant Vogtle Unit 4. For purposes of this calculation, payments made by Georgia Power on behalf of another Vogtle Owner in accordance with the second and third items described in the paragraph above will be treated as payments made by the applicable Vogtle Owner.

In the event the actual costs of construction at completion of a Unit are less than the EAC reflected in the nineteenth VCM report and such Unit is placed in service in accordance with the schedule projected in the nineteenth VCM report (i.e., Plant Vogtle Unit 3 is placed in service by November 2021 or Plant Vogtle Unit 4 is placed in service by November 2022), Georgia Power will be entitled to 60.7% of the cost savings with respect to the relevant Unit and the remaining Vogtle Owners will be entitled to 39.3% of such savings on a pro rata basis in accordance with their respective ownership interests.

For purposes of the foregoing provisions, qualifying construction costs will not include costs (i) resulting from force majeure events, including governmental actions or inactions (or significant delays associated with issuance of such actions) that affect the licensing, completion, start-up, operations, or financing of Plant Vogtle Units 3 and 4, administrative proceedings or litigation regarding ITAAC or other regulatory challenges to commencement of operation of Plant Vogtle Units 3 and 4, and changes in laws or regulations governing Plant Vogtle Units 3 and 4, (ii) legal fees and legal expenses incurred due to litigation with contractors or subcontractors that are not subsidiaries or affiliates of Southern Company, and (iii) additional costs caused by requests from the Vogtle Owners other than Georgia Power, except for the exercise of a right to vote granted under the Vogtle Joint Ownership Agreements, that increase costs by $100,000 or more.

Pursuant to the Global Amendments, and consistent with the Vogtle Owner Term Sheet, the provisions of the Vogtle Joint Ownership Agreements requiring that Vogtle Owners holding 90% of the ownership interests in Plant Vogtle Units 3 and 4 vote to continue construction following certain adverse events (Project Adverse Events) were modified. Pursuant to the Global Amendments, the holders of at least 90% of the ownership interests in Plant Vogtle Units 3 and 4 must vote to continue construction if certain Project Adverse Events occur, including: (i) the bankruptcy of Toshiba; (ii) the termination or rejection in bankruptcy of certain agreements, including the Vogtle Services Agreement, the Bechtel Agreement, or the agency agreement with Southern Nuclear; (iii) Georgia Power publicly announces its intention not to submit for rate recovery any portion of its investment in Plant Vogtle Units 3 and 4 or the Georgia PSC 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, excluding any additional amounts paid by Georgia Power on behalf of the other Vogtle Owners pursuant to the Global Amendments described above and the first 6% of costs during any six-month VCM reporting period that are disallowed by the Georgia PSC for recovery, or for which Georgia Power elects not to seek cost recovery, through retail rates; and (iv) an incremental extension of one year or more over the most recently approved schedule. Under the Global Amendments, Georgia Power may cancel the project at any time in its sole discretion.

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 Global Amendments provide that if the holders of at least 90% of the ownership interests fail to vote in favor of continuing the project following any future Project Adverse Event, work on Plant Vogtle Units 3 and 4 will continue for a period of 30 days if the holders of more than 50% of the ownership interests vote in favor of continuing construction (Majority Voting Owners). In such a case, the Vogtle Owners (i) have agreed to negotiate in good faith towards the resumption of the project, (ii) if no agreement is reached during such 30-day period, the project will be cancelled, and (iii) in the event of such a cancellation, the Majority Voting Owners will be obligated to reimburse any other Vogtle Owner for the incremental costs it incurred during such 30-day negotiation period.

Purchase of PTCs During Commercial Operation

Pursuant to the Global Amendments, and consistent with the Vogtle Owner Term Sheet, Georgia Power has agreed to purchase additional PTCs from OPC, Dalton, MEAG SPVM, MEAG SPVP, and MEAG SPVJ (to the extent any MEAG SPVJ PTC rights remain after any purchases required under the MEAG Funding Agreement as described below) at varying purchase prices dependent upon the actual cost to complete construction of Plant Vogtle Units 3 and 4 as compared to the EAC reflected in the nineteenth VCM report. The purchases are at the option of the applicable Vogtle Owner.

Potential Funding to MEAG Project J

Pursuant to the MEAG Funding Agreement, and consistent with the MEAG Term Sheet, if MEAG SPVJ is unable to make its payments due under the Vogtle Joint Ownership Agreements solely as a result of the occurrence of one of the following situations that materially impedes access to capital markets for MEAG for Project J: (i) the conduct of JEA or the City of Jacksonville, such as JEA's legal challenges of its obligations under a PPA with MEAG (PPA-J), or (ii) PPA-J is declared void by a court of competent jurisdiction or rejected by JEA under the applicable provisions of the U.S. Bankruptcy Code (each of (i) and (ii), a JEA Default), at MEAG's request, Georgia Power will purchase from MEAG SPVJ the rights to PTCs attributable to MEAG SPVJ's share of Plant Vogtle Units 3 and 4 (approximately 206 MWs) within 30 days of such request at varying prices dependent upon the stage of construction of Plant Vogtle Units 3 and 4. The aggregate purchase price of the PTCs, together with any advances made as described in the next paragraph, shall not exceed $300 million.

At the option of MEAG, as an alternative or supplement to Georgia Power's purchase of PTCs as described above, Georgia Power has agreed to provide up to $250 million in funding to MEAG for Project J in the form of advances (either advances under the Vogtle Joint Ownership Agreements or the purchase of MEAG Project J bonds, at the discretion of Georgia Power), subject to any required approvals of the Georgia PSC and the DOE.

In the event MEAG SPVJ certifies to Georgia Power that it is unable to fund its obligations under the Vogtle Joint Ownership Agreements as a result of a JEA Default and Georgia Power becomes obligated to provide funding as described above, MEAG is required to (i) assign to Georgia Power its right to vote on any future Project Adverse Event and (ii) diligently pursue JEA for its breach of PPA-J. In addition, Georgia Power agreed that it will not sue MEAG for any amounts due from MEAG SPVJ under MEAG's guarantee of MEAG SPVJ's obligations so long as MEAG SPVJ complies with the terms of the MEAG Funding Agreement as to its payment obligations and the other non-payment provisions of the Vogtle Joint Ownership Agreements.

Under the terms of the MEAG Funding Agreement, Georgia Power may cancel the project in lieu of providing funding in the form of advances or PTC purchases.

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

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 Plant Vogtle Units 3 and 4. 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. At December 31, 2018, Georgia Power had recovered approximately $1.9 billion of financing costs. Financing costs related to capital costs above $4.418 billion will be recovered through AFUDC; however, Georgia Power will not record AFUDC related to any capital costs in excess of the total deemed reasonable by the Georgia PSC (currently $7.3 billion) and not requested for rate recovery. On December 18, 2018, the Georgia PSC approved Georgia Power's request to increase the NCCR tariff by $88 million annually, effective January 1, 2019.

Georgia Power is required to file semi-annual VCM reports with the Georgia PSC by February 28 and August 31 of each year. In 2013, in connection with the eighth VCM report, the Georgia PSC approved a 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.

In 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. In December 2017, the Georgia PSC voted to approve (and issued its related order on January 11, 2018) Georgia Power's seventeenth VCM report, which included a recommendation to continue construction with Southern Nuclear as project manager and Bechtel serving as the primary construction contractor, and modified 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 $5.68 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 $5.68 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 related Customer Refunds) was 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 $100 million, $25 million, and $20 million in 2018, 2017, and 2016, respectively, and are estimated to have negative earnings impacts of approximately $75 million in 2019 and an aggregate of approximately $615 million from 2020 to 2022.

In its January 11, 2018 order, the Georgia PSC also stated if other conditions change and assumptions upon which Georgia Power's seventeenth VCM report are based do not materialize, the Georgia PSC reserved the right to reconsider the decision to continue construction.

On February 12, 2018, Georgia Interfaith Power & Light, Inc. (GIPL) and Partnership for Southern Equity, Inc. (PSE) filed a petition appealing the Georgia PSC's January 11, 2018 order with the Fulton County Superior Court. On March 8, 2018, Georgia Watch filed a similar appeal to the Fulton County Superior Court for judicial review of the Georgia PSC's decision and denial of Georgia Watch's motion for reconsideration. On December 21, 2018, the Fulton County Superior Court granted Georgia Power's motion to dismiss the two appeals. On January 9, 2019, GIPL, PSE, and Georgia Watch filed an appeal of this decision with the Georgia Court of Appeals. Georgia Power believes the appeal has no merit; however, an adverse outcome in the appeal combined with subsequent adverse action by the Georgia PSC could have a material impact on Georgia Power's results of operations, financial condition, and liquidity.

In preparation for its nineteenth VCM filing, Georgia Power requested Southern Nuclear to perform a full cost reforecast for the project. This reforecast, performed prior to the nineteenth VCM filing, resulted in a $0.7 billion increase to the base capital cost forecast reported in the second quarter 2018. This base cost increase primarily resulted from changed assumptions related to the finalization of contract scopes and management responsibilities for Bechtel and over 60 subcontractors, labor productivity rates, and craft labor incentives, as well as the related levels of project management, oversight, and support, including field supervision and engineering support.

Although Georgia Power believes these incremental costs are reasonable and necessary to complete the project and the Georgia PSC's order in the seventeenth VCM proceeding specifically states that the construction of Plant Vogtle Units 3 and 4 is not subject to a cost cap, Georgia Power did not seek rate recovery for these cost increases included in the current base capital cost forecast (or any related financing costs) in the nineteenth VCM report. In connection with future VCM filings, Georgia Power may request the Georgia PSC to evaluate costs currently included in the construction contingency estimate for rate recovery as and when they are appropriately included in the base capital cost forecast. After considering the significant level of uncertainty that exists regarding the future recoverability of costs included in the construction contingency estimate since the ultimate outcome of these matters is subject to the outcome of future assessments by management, as well as Georgia PSC decisions in these future regulatory proceedings, Georgia Power recorded a total pre-tax charge to income of $1.1 billion ($0.8 billion after tax) in the second quarter 2018, which includes the total increase in the base capital cost forecast and construction contingency estimate.

On August 31, 2018, Georgia Power filed its nineteenth VCM report with the Georgia PSC, which requested approval of $578 million of construction capital costs incurred from January 1, 2018 through June 30, 2018. On February 19, 2019, the Georgia PSC approved the nineteenth VCM, but deferred approval of $51.6 million of expenditures related to Georgia Power's portion of

an administrative claim filed in the Westinghouse bankruptcy proceedings. Through the nineteenth VCM, the Georgia PSC has approved total construction capital costs incurred through June 30, 2018 of $5.4 billion (before $1.7 billion of payments received under the Guarantee Settlement Agreement and approximately $188 million in related Customer Refunds). In addition, the staff of the Georgia PSC requested, and Georgia Power agreed, to file its twentieth VCM report concurrently with the twenty-first VCM report by August 31, 2019.

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

DOE Financing

At December 31, 2018, 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. In September 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. In September 2018, the DOE extended the conditional commitment to March 31, 2019. Any further extension must be 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 8 to the financial statements under "Long-term Debt – DOE Loan Guarantee Borrowings" for additional information, including applicable covenants, events of default, mandatory prepayment events (including any decision not to continue construction of Plant Vogtle Units 3 and 4), and conditions to borrowing.

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

Income Tax Matters

Federal Tax Reform Legislation

In December 2017, the Tax Reform Legislation was signed into law and became effective on January 1, 2018. The Tax Reform Legislation, among other things, reduced the federal corporate income tax rate to 21%, retained normalization provisions for public utility property and existing renewable energy incentives, and repealed the corporate alternative minimum tax. In addition, under the Tax Reform Legislation, net operating losses 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 at Georgia Power. See Note 10 to the financial statements for information on Southern Company's joint consolidated income tax allocation agreement.

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 provided 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, Georgia Power considered all amounts recorded in the financial statements as a result of the Tax Reform Legislation "provisional" as discussed in SAB 118 and subject to revision prior to filing its 2017 tax return in the fourth quarter 2018. Georgia Power recognized tax benefits of $50 million and $8 million in 2018 and 2017, respectively, for a total of $58 million as a result of the Tax Reform Legislation. In addition, in total, Georgia Power recorded a $147 million decrease in regulatory assets and a $3.0 billion increase in regulatory liabilities as a result of the Tax Reform Legislation and $2 million of stranded excess deferred tax balances in AOCI at December 31, 2017 were adjusted through retained earnings in 2018. As of December 31, 2018, Georgia Power considered the measurement of impacts from the Tax Reform Legislation on deferred income tax assets and liabilities, primarily due to the impact of the reduction of the corporate income tax rate, to be complete.

However, the IRS continues to issue regulations that provide further interpretation and guidance on the law and each state's adoption of the provisions contained in the Tax Reform Legislation remains uncertain. The ultimate impact of this matter cannot be determined at this time. See Note 2 to the financial statements under "Georgia Power – Rate Plans" for additional information regarding the Georgia Power Tax Reform Settlement Agreement. The regulatory treatment of certain impacts of the Tax Reform Legislation remains subject to the discretion of the Georgia PSC in the Georgia Power 2019 Base Rate Case and the FERC. Also, see FINANCIAL CONDITION AND LIQUIDITY – "Credit Rating Risk" herein and Note 10 to the financial statements under "Current and Deferred Income Taxes" for additional information.

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 $80 million for the 2018 tax year and approximately $30 million for the 2019 tax year. The ultimate outcome of this matter cannot be determined at this time.

Other Matters

Georgia Power is involved in various other matters being litigated and regulatory matters that could affect future earnings. In addition, Georgia Power is subject to certain claims and legal actions arising in the ordinary course of business. Georgia Power's business activities are subject to extensive governmental regulation related to public health and the environment, such as laws and regulations governing air, water, land, and protection of other natural resources. Litigation over environmental issues and claims of various types, including property damage, personal injury, common law nuisance, and citizen enforcement of environmental laws and regulations, 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 Notes 2 and 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 Georgia Power's financial statements. See Notes 2 and 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

Georgia Power prepares its financial statements in accordance with GAAP. Significant accounting policies are described in Notes 1, 5, and 6 to the financial statements. In the application of these policies, certain estimates are made that may have a material impact on Georgia Power'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

Georgia Power is subject to retail regulation by the Georgia PSC and wholesale regulation by the FERC. These regulatory agencies set the rates Georgia Power is permitted to charge customers based on allowable costs. As a result, Georgia Power 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 Georgia Power'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 Georgia Power; 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 Georgia Power's results of operations and financial condition than they would on a non-regulated company.

As reflected in Note 2 to the financial statements under "Georgia Power – Regulatory Assets and Liabilities," 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 Georgia Power's financial statements.

Estimated Cost, Schedule, and Rate Recovery for the Construction of Plant Vogtle Units 3 and 4

In 2016, the Georgia PSC approved the Vogtle Cost Settlement Agreement, which resolved certain prudency matters in connection with Georgia Power's fifteenth VCM report. In December 2017, the Georgia PSC approved Georgia Power's seventeenth VCM

report, 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, as well as a modification of the Vogtle Cost Settlement Agreement. The Georgia PSC's related order stated that under the modified Vogtle Cost Settlement Agreement, (i) none of the $3.3 billion of costs incurred through December 31, 2015 should be disallowed as imprudent; (ii) capital costs incurred up to $5.68 billion would be presumed to be reasonable and prudent with the burden of proof on any party challenging such costs; (iii) Georgia Power would have the burden of proof to show that any capital costs above $5.68 billion were prudent; (iv) Georgia Power's total project capital cost forecast of $7.3 billion (net of $1.7 billion received under the Guarantee Settlement Agreement and approximately $188 million in related Customer Refunds) was found reasonable and did not represent a cost cap; and (v) prudence decisions would be made subsequent to achieving fuel load for Unit 4.

In its order, the Georgia PSC also stated if other conditions change and assumptions upon which Georgia Power's seventeenth VCM report are based do not materialize, the Georgia PSC reserved the right to reconsider the decision to continue construction.

In the second quarter 2018, Georgia Power revised its base cost forecast and estimated contingency to complete construction and start-up of Plant Vogtle Units 3 and 4 to $8.0 billion and $0.4 billion, respectively, for a total project capital cost forecast of $8.4 billion (net of $1.7 billion received under the Guarantee Settlement Agreement and approximately $188 million in related Customer Refunds). Although Georgia Power believes these incremental costs are reasonable and necessary to complete the project and the Georgia PSC's order in the seventeenth VCM proceeding specifically states that the construction of Plant Vogtle Units 3 and 4 is not subject to a cost cap, Georgia Power did not seek rate recovery for the $0.7 billion increase in costs included in the current base capital cost forecast in the nineteenth VCM report. In connection with future VCM filings, Georgia Power may request the Georgia PSC to evaluate costs currently included in the construction contingency estimate for rate recovery as and when they are appropriately included in the base capital cost forecast. After considering the significant level of uncertainty that exists regarding the future recoverability of costs included in the construction contingency estimate since the ultimate outcome of these matters is subject to the outcome of future assessments by management, as well as Georgia PSC decisions in these future regulatory proceedings, Georgia Power recorded a total pre-tax charge to income of $1.1 billion ($0.8 billion after tax) in the second quarter 2018.

Georgia Power's revised cost estimate reflects an expected in-service date of November 2021 for Unit 3 and November 2022 for Unit 4.

As construction continues, challenges with management of contractors, subcontractors, and vendors; labor productivity, availability, and/or cost escalation; procurement, fabrication, delivery, assembly, and/or installation and testing, including any required engineering changes, of plant systems, structures, and components (some of which are based on new technology that only recently began initial operation in the global nuclear industry at this scale); or other issues could arise and change the projected schedule and estimated cost. Monthly construction production targets required to maintain the current project schedule will continue to increase significantly throughout 2019. To meet these increasing monthly targets, existing craft construction productivity must improve and additional craft laborers must be retained and deployed.

Georgia Power and Southern Nuclear believe it is a leading practice in connection with a construction project of this size and complexity to periodically validate recent construction progress in comparison to the projected schedule and to verify and update quantities of commodities remaining to install, labor productivity, and forecasted staffing needs. This verification process, led by Southern Nuclear, was underway as of December 31, 2018 and is expected to be completed during the second quarter 2019. Georgia Power currently does not anticipate any material changes to the total estimated project capital cost forecast for Plant Vogtle Units 3 and 4 or the expected in-service dates of November 2021 and November 2022, respectively, resulting from this verification process. However, the ultimate impact on cost and schedule, if any, will not be known until the verification process is completed. Georgia Power is required to report the results and any project impacts to the Georgia PSC by May 15, 2019.

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 ITAAC 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. Any extension of the in-service dates of November 2021 for Unit 3 and November 2022 for Unit 4 is currently estimated to result in additional base capital costs of approximately $50 million per month, based on Georgia Power's ownership interests, and AFUDC of approximately $12 million per month. While

Georgia Power is not precluded from seeking recovery of any future capital cost forecast increase, management will ultimately determine whether or not to seek recovery. Any further changes to the capital cost forecast that are not expected to be recoverable through regulated rates will be required to be charged to income and such charges could be material.

Given the significant complexity involved in estimating the future costs to complete construction and start-up of Plant Vogtle Units 3 and 4 and the significant management judgment necessary to assess the related uncertainties surrounding future rate recovery of any projected cost increases, as well as the potential impact on Georgia Power's results of operations and cash flows, Georgia Power considers these items to be critical accounting estimates. See Note 2 to the financial statements under "Georgia Power – Nuclear Construction" for additional information.

Asset Retirement Obligations

AROs are computed as the fair value of the estimated costs for an asset's future retirement and are recorded in the period in which the liability is incurred. The estimated 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 Georgia Power's nuclear facilities, which include Georgia Power's ownership interests in Plant Hatch and Plant Vogtle Units 1 and 2, and facilities that are subject to the CCR Rule and the related state rule, principally ash ponds. In addition, Georgia Power has AROs related to various landfill sites, underground storage tanks, and asbestos removal.

Georgia Power 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 Georgia Power'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 retirement obligations will be recognized when sufficient information becomes available to support a reasonable estimation of the retirement obligation.

Georgia Power 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 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 and the related state rule. In December 2018, Georgia Power recorded an increase of approximately $3.1 billion to its AROs related to the disposal of CCR as a result of a strategic assessment which indicated additional closure costs will be required to close the ash ponds, primarily due to changes in closure strategies, the estimated amount of ash to be excavated, and additional water management requirements necessary to support closure strategies. Also in December 2018, Georgia Power recorded an increase of approximately $130 million to its AROs as a result of updated decommissioning cost site studies for Plant Hatch and Plant Vogtle Units 1 and 2. Georgia Power expects to periodically update its ARO cost estimates. See FUTURE EARNINGS POTENTIAL – "Environmental Matters – Environmental Laws and Regulations – Coal Combustion Residuals" herein and Note 6 to the financial statements for additional information.

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

Pension and Other Postretirement Benefits

Georgia Power'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 Georgia Power believes that the assumptions used are appropriate, differences in actual experience or significant changes in assumptions would affect its pension and other postretirement benefit costs and obligations.

Key elements in determining Georgia Power'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 Georgia Power's 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.

A 25 basis point change in any significant assumption (discount rate, salary increases, or long-term rate of return on plan assets) would result in a $10 million or less change in total annual benefit expense, a $128 million or less change in the projected obligation for the pension plan, and an $18 million or less change in the projected obligation for other postretirement benefit plans.

See Note 11 to the financial statements for additional information regarding pension and other postretirement benefits.

Contingent Obligations

Georgia Power 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 Notes 2 and 3 to the financial statements for more information regarding certain of these contingencies. Georgia Power 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 Georgia Power's results of operations, cash flows, or financial condition.

Recently Issued Accounting Standards

See Note 1 to the financial statements under "Recently Adopted Accounting Standards" for additional information.

In 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 Georgia Power adopted the new standard effective January 1, 2019.

Georgia Power elected the transition methodology provided by ASU No. 2018-11, *Leases (Topic 842): Targeted Improvements*, whereby the requirements of ASU 2016-02 are applied on a prospective basis as of the adoption date of January 1, 2019, without restating prior periods. Georgia Power elected the package of practical expedients provided by ASU 2016-02 that allows prior determinations of whether existing contracts are, or contain, leases and the classification of existing leases to continue without reassessment. Additionally, Georgia Power applied the use-of-hindsight practical expedient in determining lease terms as of the date of adoption and elected the practical expedient that allows existing land easements not previously accounted for as leases not to be reassessed. Georgia Power also made accounting policy elections to account for short-term leases in all asset classes as off-balance sheet leases and combined lease and non-lease components in the computations of lease obligations and right-of-use assets for most asset classes.

Georgia Power completed the implementation of a new application to track and account for its leases and updated its internal controls and accounting policies to support the accounting for leases under ASU 2016-02. Georgia Power completed its lease inventory and determined its most significant leases involve PPAs and real estate. In the first quarter 2019, the adoption of ASU 2016-02 resulted in recording lease liabilities and right-of-use assets on Georgia Power's balance sheet each totaling approximately $1.5 billion, with no impact on Georgia Power's statement of income.

FINANCIAL CONDITION AND LIQUIDITY

Overview

Georgia Power's financial condition remained stable at December 31, 2018. Georgia Power'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 and closures of ash ponds, to expand and improve transmission and distribution facilities, and for restoration following major storms. Operating cash flows provide a substantial portion of Georgia Power's cash needs. For the three-year period from 2019 through 2021, Georgia Power's projected common stock dividends, capital expenditures, and debt maturities are expected to exceed operating cash flows. Georgia Power plans to finance future cash needs in excess of its operating cash flows primarily through external securities issuances, equity contributions from Southern Company, borrowings from financial

institutions, and borrowings through the FFB. Georgia Power plans to use commercial paper to manage seasonal variations in operating cash flows and for other working capital needs. Georgia Power 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.

Georgia Power's investments in the qualified pension plan and nuclear decommissioning trust funds decreased in value as of December 31, 2018 as compared to December 31, 2017. No contributions to the qualified pension plan were made for the year ended December 31, 2018 and no mandatory contributions to the qualified pension plan are anticipated during 2019. Georgia Power also funded approximately $5 million to its nuclear decommissioning trust funds in 2018. See "Contractual Obligations" herein and Notes 6 and 11 to the financial statements under "Nuclear Decommissioning" and "Pension Plans," respectively, for additional information.

Net cash provided from operating activities totaled $2.8 billion in 2018, an increase of $857 million from 2017, primarily due to the timing of vendor and property tax payments and income tax refunds, a decrease in current income taxes related to the Tax Reform Legislation, increased fuel cost recovery, and the timing of fossil fuel stock purchases, partially offset by payments of customer refunds primarily related to the Guarantee Settlement Agreement and the Georgia Power Tax Reform Settlement Agreement. 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. See FUTURE EARNINGS POTENTIAL – "Income Tax Matters – Federal Tax Reform Legislation" herein and Note 10 to the financial statements for additional information regarding federal income taxes.

Net cash used for investing activities totaled $3.1 billion, $0.9 billion, and $2.3 billion in 2018, 2017, and 2016, respectively, due to gross property additions primarily related to installation of equipment to comply with environmental standards and construction of generation, transmission, and distribution facilities, including a total of $2.7 billion related to the construction of Plant Vogtle Units 3 and 4, partially offset in 2017 by $1.7 billion in payments received under the Guarantee Settlement Agreement. 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 $400 million, $151 million, and $142 million for 2018, 2017, and 2016, respectively. The increase in cash used in 2018 compared to 2017 was primarily due to lower issuances of senior notes and short-term bank debt and higher redemptions and repurchases of senior notes, partially offset by higher capital contributions from Southern Company and an increase in notes payable. 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 Georgia Power'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. 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 2018 included an increase in property, plant, and equipment of $2.6 billion primarily related to the $3.2 billion increase in AROs, as well as the installation of equipment to comply with environmental standards and the construction of generation, transmission, and distribution facilities, and net of the $1.1 billion charge related to the construction of Plant Vogtle Units 3 and 4; an increase of $2.0 billion in other regulatory assets, deferred primarily related to AROs; and a decrease of $1.9 billion in long-term debt (including securities due within one year) primarily due to the redemption, repurchase, and maturity of senior notes and the purchase of pollution control revenue bonds. Total common stockholder's equity increased $2.4 billion primarily due to a $3.0 billion increase in paid-in capital resulting from capital contributions received from Southern Company, partially offset by a $0.6 billion decrease in retained earnings primarily due to the charge related to Plant Vogtle Units 3 and 4. See Note 6 to the financial statements for additional information on AROs and Note 2 to the financial statements under "Georgia Power – Nuclear Construction" for additional information regarding Plant Vogtle Units 3 and 4.

Georgia Power's ratio of common equity to total capitalization plus short-term debt was 58.2% at December 31, 2018 and 49.7% at December 31, 2017. See Note 8 to the financial statements for additional information.

Sources of Capital

Georgia Power 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, 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. At December 31, 2018, Georgia Power had borrowed $2.6 billion under the FFB Credit Facility. In July 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.

In September 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 March 31, 2019, 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 8 to the financial statements under "Long-term Debt – DOE Loan Guarantee Borrowings" for additional information regarding the Loan Guarantee Agreement, including applicable covenants, events of default, mandatory prepayment events (including any decision not to continue construction of Plant Vogtle Units 3 and 4), and additional conditions to borrowing. Also see Note 2 to the financial statements under "Georgia Power – Nuclear Construction" for additional information regarding Plant Vogtle Units 3 and 4.

The issuance of long-term securities by Georgia Power is subject to the approval of the Georgia PSC. In addition, the issuance of short-term debt securities by Georgia Power is subject to regulatory approval by the FERC. Additionally, with respect to the public offering of securities, Georgia Power 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.

Georgia Power obtains financing separately without credit support from any affiliate. See Note 8 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 Georgia Power are not commingled with funds of any other company in the Southern Company system.

At December 31, 2018, Georgia Power's current liabilities exceeded current assets by $1.4 billion primarily as a result of $0.6 billion of long-term debt that is due within one year and $0.3 billion of notes payable. Georgia Power'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.

At December 31, 2018, Georgia Power had approximately $4 million of cash and cash equivalents. Georgia Power's committed credit arrangement with banks was $1.75 billion at December 31, 2018, of which $1.74 billion was unused. This credit arrangement expires in 2022.

This bank credit arrangement contains a covenant that limits debt levels and contains a cross-acceleration provision to other indebtedness (including guarantee obligations) of Georgia Power. Such cross-acceleration provision to other indebtedness would trigger an event of default if Georgia Power defaulted on indebtedness, the payment of which was then accelerated. At December 31, 2018, Georgia Power 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, Georgia Power expects to renew or replace this credit arrangement as needed prior to expiration. In connection therewith, Georgia Power may extend the maturity date and/or increase or decrease the lending commitments thereunder.

See Note 8 to the financial statements under "Bank Credit Arrangements" for additional information.

A portion of the $1.74 billion unused credit with banks is allocated to provide liquidity support to Georgia Power's pollution control revenue bonds and commercial paper program. The amount of variable rate pollution control revenue bonds outstanding requiring liquidity support at December 31, 2018 was $659 million as compared to $550 million at December 31, 2017. In addition, at December 31, 2018, Georgia Power had obligations related to $345 million of pollution control revenue bonds outstanding that are required to be remarketed within the next 12 months. Subsequent to December 31, 2018, Georgia Power redeemed approximately $108 million of these obligations.

Georgia Power 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 Georgia Power and the other traditional electric operating companies. Proceeds from such issuances for the benefit of Georgia Power are loaned directly to Georgia Power. The obligations of each

traditional electric operating company under these arrangements are several and there is no cross-affiliate credit support. Short-term borrowings are included in notes payable in the balance sheets.

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, 2018:					
Commercial paper	**$ 294**	**3.1%**	**$ 127**	**2.5%**	**$ 710**
Short-term bank debt	**—**	**—%**	**12**	**2.3%**	**150**
Total	**$ 294**	**3.1%**	**$ 139**	**2.5%**	
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

(*) Average and maximum amounts are based upon daily balances during the 12-month periods ended December 31, 2018, 2017, and 2016.

Georgia Power 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, Georgia Power plans to continue, when economically feasible, a program to retire higher-cost securities and replace these obligations with lower-cost capital if market conditions permit.

Senior Notes

In April 2018, Georgia Power redeemed all $250 million aggregate principal amount of its Series 2008B 5.40% Senior Notes due June 1, 2018.

In May 2018, through cash tender offers, Georgia Power repurchased and retired $89 million of the $250 million aggregate principal amount outstanding of its Series 2007A 5.65% Senior Notes due March 1, 2037, $326 million of the $500 million aggregate principal amount outstanding of its Series 2009A 5.95% Senior Notes due February 1, 2039, and $335 million of the $600 million aggregate principal amount outstanding of its Series 2010B 5.40% Senior Notes due June 1, 2040, for an aggregate purchase price, excluding accrued and unpaid interest, of $902 million.

In December 2018, Georgia Power repaid at maturity $500 million aggregate principal amount of its Series 2015A 1.95% Senior Notes.

Pollution Control Revenue Bonds

During 2018, Georgia Power purchased and held the following pollution control revenue bonds, which may be reoffered to the public at a later date:

- approximately $105 million aggregate principal amount of Development Authority of Burke County (Georgia) Pollution Control Revenue Bonds (Georgia Power Company Plant Vogtle Project), First Series 2013
- $173 million aggregate principal amount of Development Authority of Bartow County (Georgia) Pollution Control Revenue Bonds (Georgia Power Company Plant Bowen Project), First Series 2009
- $55 million aggregate principal amount of Development Authority of Burke County (Georgia) Pollution Control Revenue Bonds (Georgia Power Company Plant Vogtle Project), Fifth Series 1994

- $65 million aggregate principal amount of Development Authority of Burke County (Georgia) Pollution Control Revenue Bonds (Georgia Power Company Plant Vogtle Project), Second Series 2008
- approximately $72 million aggregate principal amount of Development Authority of Bartow County (Georgia) Pollution Control Revenue Bonds (Georgia Power Company Plant Bowen Project), First Series 2013

In December 2018, the Development Authority of Burke County (Georgia) issued approximately $108 million aggregate principal amount of Pollution Control Revenue Bonds (Georgia Power Company Plant Vogtle Project), First Series 2018 due November 1, 2052 for the benefit of Georgia Power. The proceeds were used to redeem, in January 2019, approximately $13 million, $20 million, and $75 million aggregate principal amount of Development Authority of Burke County (Georgia) Pollution Control Revenue Bonds (Georgia Power Company Plant Vogtle Project), First Series 1992, Eighth Series 1994, and Second Series 1995, respectively.

Other

In January 2018, Georgia Power 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, 2018, Georgia Power 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, 2018 were as follows:

Credit Ratings	Maximum Potential Collateral Requirements
	(in millions)
At BBB- and/or Baa3	$ 92
Below BBB- and/or Baa3	$ 1,106

Included in these amounts are certain agreements that could require collateral in the event that either Georgia Power or Alabama Power (an affiliate of 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 Georgia Power to access capital markets and would be likely to impact the cost at which it does so.

On February 28, 2018, Fitch downgraded the senior unsecured long-term debt rating of Georgia Power to A from A+ with a negative outlook. On August 9, 2018, Fitch downgraded the senior unsecured long-term debt rating of Georgia Power to A- from A. On September 28, 2018, Fitch assigned a negative rating outlook to the ratings of Southern Company and certain of its subsidiaries (including Georgia Power).

On August 8, 2018, Moody's downgraded the senior unsecured debt rating of Georgia Power to Baa1 from A3. On September 28, 2018, Moody's revised its rating outlook for Georgia Power from negative to stable.

As a result of 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 Georgia Power) may be negatively impacted. The Georgia Power Tax Reform Settlement Agreement approved by the Georgia PSC on April 3, 2018 is expected to help mitigate these potential adverse impacts to certain credit metrics by allowing a higher retail equity ratio until the conclusion of the Georgia Power 2019 Base Rate Case. See Note 2 to the financial statements under "Georgia Power – Rate Plans" for additional information.

Market Price Risk

Due to cost-based rate regulation and other various cost recovery mechanisms, Georgia Power 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, Georgia Power nets the exposures, where possible, to take advantage of natural offsets and enters into various

derivative transactions for the remaining exposures pursuant to Georgia Power's policies in areas such as counterparty exposure and risk management practices. Georgia Power'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, Georgia Power may enter into derivatives designated as hedges. The weighted average interest rate on $0.9 billion of long-term variable interest rate exposure at December 31, 2018 was 2.57%. If Georgia Power sustained a 100 basis point change in interest rates for all long-term variable interest rate exposure, the change would affect annualized interest expense by approximately $9 million at December 31, 2018. See Note 1 to the financial statements under "Financial Instruments" and Note 14 to the financial statements for additional information.

To mitigate residual risks relative to movements in electricity prices, Georgia Power 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. Georgia Power continues to manage a fuel-hedging program implemented per the guidelines of the Georgia PSC. Georgia Power had no material change in market risk exposure for the year ended December 31, 2018 when compared to the December 31, 2017 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:

	2018 Changes	2017 Changes
	Fair Value	
	(in millions)	
Contracts outstanding at the beginning of the period, assets (liabilities), net	**$ (13)**	$ 36
Contracts realized or settled:		
Swaps realized or settled	**1**	(13)
Options realized or settled	**—**	(1)
Current period changes(*):		
Swaps	**(3)**	(28)
Options	**1**	(7)
Contracts outstanding at the end of the period, assets (liabilities), net	**$ (14)**	$ (13)

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

The net hedge volumes of energy-related derivative contracts at December 31, 2018 and 2017 were as follows:

	2018	2017
	mmBtu Volume	
	(in millions)	
Commodity – Natural gas swaps	**141**	146
Commodity – Natural gas options	**12**	17
Total hedge volume	**153**	163

The weighted average swap contract cost above market prices was approximately $0.10 per mmBtu and $0.08 per mmBtu at December 31, 2018 and 2017, respectively. 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 Georgia Power's fuel cost recovery mechanism.

At December 31, 2018 and 2017, substantially all of Georgia Power's energy-related derivative contracts were designated as regulatory hedges and were related to Georgia Power's fuel-hedging program, which had a time horizon up to 48 months. Hedging gains and losses are initially recorded as regulatory liabilities and assets, respectively, and then are included in fuel expense as they are recovered through the fuel cost recovery mechanism. Gains and losses on energy-related derivative contracts that are not designated or fail to qualify as hedges are recognized in the statements of income as incurred and were not material for any year presented.

Georgia Power 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 13 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, 2018 were as follows:

	Fair Value Measurements December 31, 2018		
	Total Fair Value	Maturity	
		Year 1	Years 2&3
	(in millions)		
Level 1	$ —	$ —	$ —
Level 2	(14)	(6)	(8)
Level 3	—	—	—
Fair value of contracts outstanding at end of period	$ (14)	$ (6)	$ (8)

Georgia Power is exposed to market price risk in the event of nonperformance by counterparties to the energy-related and interest rate derivative contracts. Georgia Power 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, Georgia Power 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 14 to the financial statements.

Capital Requirements and Contractual Obligations

The construction program of Georgia Power is currently estimated to total $3.7 billion for 2019, $3.5 billion for 2020, $3.4 billion for 2021, $3.4 billion for 2022, and $2.9 billion for 2023. These amounts include expenditures of approximately $1.5 billion, $1.2 billion, $1.0 billion, and $0.5 billion for the construction of Plant Vogtle Units 3 and 4 in 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 $0.2 billion, $0.1 billion, $0.1 billion, $0.2 billion, and $0.1 billion for 2019, 2020, 2021, 2022, and 2023, respectively. These estimated expenditures do not include any potential compliance costs associated with pending 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.

Georgia Power also anticipates costs associated with closure and monitoring of ash ponds and landfills in accordance with the CCR Rule, which are reflected in Georgia Power's ARO liabilities. In December 2018, Georgia Power recorded an increase of approximately $3.1 billion to its AROs related to the CCR Rule and the related state rule. These costs, which are expected to change and could change materially as underlying assumptions are refined and the cost and the method and timing of compliance activities continue to be evaluated, are currently estimated to be $0.2 billion for 2019, $0.3 billion for 2020, $0.4 billion for 2021, $0.7 billion for 2022, and $0.6 billion for 2023. See FUTURE EARNINGS POTENTIAL – "Environmental Matters – Environmental Laws and Regulations – Coal Combustion Residuals" and Note 6 to the financial statements 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 includes components based on new technology that only recently began initial operation in the global nuclear industry at this scale and which may be subject to additional revised cost estimates during construction. The ability to control costs and avoid cost and schedule 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, availability, and productivity; challenges with management of contractors, subcontractors, or vendors; adverse weather conditions; shortages, increased costs, or 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; engineering or design problems; design and other licensing-based compliance matters, including the timely resolution of ITAAC and the related approvals by the NRC; challenges with start-up activities, including major equipment failure and system integration; and/or operational performance. See Note 2 to the financial statements under "Georgia Power – Nuclear Construction" for information regarding additional factors that may impact construction expenditures.

As a result of requirements by the NRC, Georgia Power has established external trust funds for nuclear decommissioning costs. For additional information, see Note 6 to the financial statements under "Nuclear Decommissioning."

In addition, as discussed in Note 11 to the financial statements, Georgia Power provides postretirement benefits to substantially all employees and funds trusts to the extent required by the Georgia PSC and the FERC.

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, ARO settlements, and trusts are detailed in the contractual obligations table that follows. See Notes 1, 6, 8, 9, 11, and 14 to the financial statements for additional information.

Contractual Obligations

Contractual obligations at December 31, 2018 were as follows:

	2019	2020-2021	2022-2023	After 2023	Total
			(in millions)		
Long-term debt[a] —					
Principal	$ 608	$ 1,363	$ 641	$ 7,343	$ 9,955
Interest	339	615	562	4,660	6,176
Financial derivative obligations[b]	8	12	—	—	20
Operating leases[c]	23	27	11	13	74
Capital leases[c]	9	7	—	—	16
Purchase commitments —					
Capital[d]	3,512	6,305	5,876		15,693
Fuel[e]	1,117	1,400	764	4,586	7,867
Purchased power[f]	270	536	549	2,054	3,409
Other[g]	42	179	109	267	597
ARO settlements[h]	202	674	1,283		2,159
Trusts —					
Nuclear decommissioning[i]	5	11	11	88	115
Pension and other postretirement benefit plans[j]	43	79			122
Total	$ 6,178	$ 11,208	$ 9,806	$ 19,011	$ 46,203

(a) All amounts are reflected based on final maturity dates except for amounts related to FFB borrowings and certain pollution control 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 8 to the financial statements under "Long-term Debt – DOE Loan Guarantee Borrowings" for additional information. Georgia Power 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, 2018, 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 14 to the financial statements.

(c) Excludes PPAs that are accounted for as leases and included in "Purchased power." See Note 8 to the financial statements under "Long-term Debt – Capital Leases – Georgia Power" and Note 9 to the financial statements under "Operating Leases" for additional information.

(d) Georgia Power 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, capital expenditures covered under LTSAs, and estimated capital expenditures for AROs, which are reflected in "Fuel," "Other," and "ARO settlements," respectively. At December 31, 2018, 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 NYMEX future prices at December 31, 2018.

(f) Estimated minimum long-term obligations for various PPA purchases from gas-fired, biomass, and wind-powered facilities and capacity payments related to Plant Vogtle Units 1 and 2. See Note 9 to the financial statements under "Fuel and Power Purchase Agreements" for additional information.

(g) Includes LTSAs and contracts for the procurement of limestone. LTSAs include price escalation based on inflation indices.

(h) Represents estimated costs for a five-year period associated with closing and monitoring ash ponds and landfills in accordance with the CCR Rule and the related state rule, which are reflected in Georgia Power's AROs. Material expenditures in future years for ARO settlements also will be required for ash ponds, nuclear decommissioning, and other liabilities and are reflected in Georgia Power's AROs. See FUTURE EARNINGS POTENTIAL – "Environmental Matters – Environmental Laws and Regulations – Coal Combustion Residuals" herein and Note 6 to the financial statements for additional information.

(i) Projections of nuclear decommissioning trust fund contributions for Plant Hatch and Plant Vogtle Units 1 and 2 are based on the 2013 ARP. See Note 6 to the financial statements under "Nuclear Decommissioning" for additional information.

(j) Georgia Power forecasts contributions to the pension and other postretirement benefit plans over a three-year period. Georgia Power 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 Georgia Power's corporate assets. See Note 11 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 Georgia Power's corporate assets.

OVERVIEW

Business Activities

Mississippi Power 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 Mississippi Power's business of providing electric service. These factors include Mississippi Power'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 Mississippi Power for the foreseeable future. Mississippi Power is scheduled to file a base rate case in the fourth quarter 2019 (Mississippi Power 2019 Base Rate Case).

As a result of the Mississippi PSC's stated intent to issue an order establishing a new docket for a global settlement under which the Kemper County energy facility would be operated as a natural gas plant, rather than an IGCC plant (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. 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. In the aggregate, Mississippi Power had incurred charges of $3.07 billion ($1.89 billion after tax) for changes in the cost estimate above the cost cap through May 31, 2017.

Given the Mississippi PSC's stated intent regarding no additional rate increases for the Kemper County energy facility and the subsequent suspension of construction, cost recovery of the gasification portions was no longer probable. Therefore, Mississippi Power recorded a charge to income in June 2017 of $2.8 billion ($2.0 billion after tax) for the estimated costs associated with the gasification portions of the plant and lignite mine. During the third and fourth quarters 2017, Mississippi Power recorded further charges to income totaling $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 associated with the Kemper Settlement Agreement discussed below.

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), which resolved all cost recovery issues, modified the CPCN to limit the Kemper County energy facility to natural gas combined cycle operation, and provided for an annual revenue requirement of approximately $99.3 million for costs related to the Kemper County energy facility, which included the impact of the 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 reflect a reduction of approximately $26.8 million annually, effective with the first billing cycle of April 2018, and include no recovery for costs associated with the gasifier portion of the Kemper County energy facility in 2018 or at any future date.

In 2018, Mississippi Power recorded pre-tax charges to income of $37 million ($27 million after tax), primarily resulting from the abandonment and related closure activities and ongoing period costs, net of sales proceeds, for the mine and gasifier-related assets at the Kemper County energy facility. In addition, Mississippi Power recorded a credit to earnings of $95 million in the fourth quarter 2018 primarily resulting from the reduction of a valuation allowance for a state income tax net operating loss (NOL) carryforward associated with the Kemper County energy facility. Additional closure costs for the mine and gasifier-related assets, currently estimated at up to $10 million pre-tax (excluding salvage, net of dismantlement costs), may be incurred through the first half of 2020. In addition, period costs, including, but not limited to, costs for compliance and safety, ARO accretion, and property taxes for the mine and gasifier-related assets, are estimated to total $11 million in 2019 and $2 million to $4 million annually in 2020 through 2023. Mississippi Power is currently evaluating its options regarding the final disposition of the CO_2 pipeline, including removal of the pipeline. This evaluation is expected to be complete later in 2019. If Mississippi Power ultimately decides to remove the CO_2 pipeline, the cost of removal would have a material impact on Mississippi Power's financial statements. The ultimate outcome of these matters cannot be determined at this time.

See Note 2 to the financial statements under "Kemper County Energy Facility" and Note 10 to the financial statements for additional information.

On August 7, 2018 the Mississippi PSC approved settlement agreements between Mississippi Power and the MPUS with respect to the 2018 PEP filing and all unresolved PEP filings for prior years (PEP Settlement Agreement) and the 2018 ECO Plan filing (ECO Settlement Agreement). Rates under the PEP Settlement Agreement and the ECO Settlement Agreement resulted in annual revenue increases of approximately $21.6 million and $17 million, respectively, effective with the first billing cycle of September 2018 and are expected to continue through the conclusion of the Mississippi Power 2019 Base Rate Case.

In August 2018, the Mississippi PSC began an operations review of Mississippi Power, for which the final report is expected prior to the conclusion of the Mississippi Power 2019 Base Rate Case. Mississippi Power expects that the review will include, but not be limited to, a comparative analysis of its costs, its cost recovery framework, and ways in which it may streamline management operations for the reasonable benefit of ratepayers. The ultimate outcome of this matter cannot be determined at this time.

See FUTURE EARNINGS POTENTIAL – "Retail Regulatory Matters" herein and Note 2 to the financial statements under "Mississippi Power" for additional information.

Mississippi Power continues to focus on several key performance indicators. In recognition that Mississippi Power's long-term financial success is dependent upon how well it satisfies its customers' needs, Mississippi Power's retail base rate mechanism, PEP, includes performance indicators that directly tie customer service indicators to Mississippi Power's allowed ROE. PEP measures Mississippi Power'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%). Mississippi Power also focuses on broader measures of customer satisfaction, plant availability, system reliability, and net income.

Mississippi Power'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 Mississippi Power's results and generally targets top-quartile performance.

See RESULTS OF OPERATIONS herein for information on Mississippi Power's financial performance.

Earnings

Mississippi Power's net income after dividends on preferred stock was $235 million in 2018 compared to a $2.59 billion net loss in 2017 and a $50 million net loss in 2016. The changes were primarily the result of pre-tax charges associated with the Kemper IGCC of $37 million, $3.36 billion, and $428 million, in 2018, 2017, and 2016, respectively. The increase in net income in 2018 was partially offset by lower tax benefits and a decrease in AFUDC. See Note 2 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	
	2018	2018	2017
		(in millions)	
Operating revenues	$ 1,265	$ 78	$ 24
Fuel	405	10	52
Purchased power	41	16	(9)
Other operations and maintenance	313	22	(26)
Depreciation and amortization	169	8	29
Taxes other than income taxes	107	3	(5)
Estimated loss on Kemper IGCC	37	(3,325)	2,934
Total operating expenses	1,072	(3,266)	2,975
Operating income	193	3,344	(2,951)
Allowance for equity funds used during construction	—	(72)	(52)
Interest expense, net of amounts capitalized	76	34	(32)
Other income (expense), net	17	16	3
Income taxes (benefit)	(102)	430	(428)
Net income	236	2,824	(2,540)
Dividends on preferred stock	1	(1)	—
Net income after dividends on preferred stock	$ 235	$ 2,825	$ (2,540)

Operating Revenues

Operating revenues for 2018 were $1.3 billion, reflecting a $78 million increase from 2017. Details of operating revenues were as follows:

	2018	2017
	(in millions)	
Retail — prior year	$ 854	$ 859
Estimated change resulting from —		
Rates and pricing	24	(7)
Sales growth	4	4
Weather	12	(15)
Fuel and other cost recovery	(5)	13
Retail — current year	889	854
Wholesale revenues —		
Non-affiliates	263	259
Affiliates	91	56
Total wholesale revenues	354	315
Other operating revenues	22	18
Total operating revenues	$ 1,265	$ 1,187
Percent change	6.6%	2.1%

Total retail revenues for 2018 increased $35 million, or 4.1%, compared to 2017 primarily due to the PEP and ECO Plan rate changes that became effective for the first billing cycle of September 2018, each resulting in retail revenue increases of $12 million. In addition, as a result of the PEP Settlement Agreement, Mississippi Power recognized revenues of $5 million previously

reserved in connection with the 2012 PEP lookback filing and deferred $17 million of revenue in 2017 following the complete amortization of certain regulatory assets related to the Kemper County energy facility. These increases were offset by a decrease of $16 million annually for base rates related to the Kemper County energy facility that became effective for the first billing cycle of April 2018 and the recognition in 2018 of regulatory liabilities of $5 million and $2 million, respectively, related to the equity ratio provisions of the PEP and ECO Settlement Agreements. Additionally, there was a $12 million increase as a result of colder weather in the first quarter and warmer weather in the second and third quarters in 2018 as compared to the corresponding periods in 2017 and a $5 million decrease in fuel and other cost recovery.

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 as compared to 2016 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.

See Note 2 to the financial statements under "Mississippi Power – Environmental Compliance Overview Plan," " – Performance Evaluation Plan," 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 Mississippi Power 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 Mississippi Power'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:

	2018	2017	2016
		(in millions)	
Capacity and other	**$ 6**	$ 15	$ 16
Energy	**257**	244	245
Total non-affiliated	**$ 263**	$ 259	$ 261

Wholesale revenues from sales to non-affiliates will vary depending on fuel prices, the market prices of wholesale energy compared to the cost of Mississippi Power's and the Southern Company system's generation, demand for energy within the Southern Company system's electric service territory, and the availability of the Southern Company system's generation. Increases and decreases in energy revenues that are driven by fuel prices are accompanied by an increase or decrease in fuel costs and do not have a significant impact on net income. In addition, Mississippi Power 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 17.3% of Mississippi Power's total operating revenues in 2018 and are generally subject to 10-year rolling 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 Mississippi Power'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 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 $35 million, or 62.5%, in 2018 compared to 2017 and increased $30 million, or 115.4%, in 2017 compared to 2016. The increases in 2018 and 2017 were primarily due to $19 million and $9 million, respectively, associated with higher natural gas prices and $16 million and $21 million, respectively, associated with increases in KWH sales due to the dispatch of Mississippi Power's lower cost generation resources to serve Southern Company system territorial load.

Energy Sales

Changes in revenues are influenced heavily by the change in the volume of energy sold from year to year. KWH sales for 2018 and the percent change from the prior year were as follows:

	Total KWHs	Total KWH Percent Change		Weather-Adjusted Percent Change	
	2018	**2018**	2017	**2018**	2017
	(in millions)				
Residential	**2,113**	**8.7%**	(5.2)%	**1.4%**	1.4 %
Commercial	**2,797**	**1.2**	(2.7)	**(0.7)**	(0.1)
Industrial	**4,924**	**1.7**	(1.3)	**1.7**	(1.3)
Other	**37**	**(4.1)**	(1.6)	**(4.1)**	(1.6)
Total retail	**9,871**	**2.9**	(2.5)	**0.9%**	(0.4)%
Wholesale					
Non-affiliated	**3,980**	**8.4**	(6.3)		
Affiliated	**2,584**	**27.7**	82.7		
Total wholesale	**6,564**	**15.3**	14.0		
Total energy sales	**16,435**	**7.5%**	2.8 %		

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 increased 2.9% in 2018 as compared to the prior year. This increase was primarily the result of colder weather in the first quarter and warmer weather in the second and third quarters 2018 as compared to the corresponding periods in 2017. Weather-adjusted residential KWH sales increased in 2018 primarily due to increased customer usage. Weather-adjusted commercial KWH sales decreased primarily due to decreased customer usage slightly offset by customer growth. The increase in industrial KWH energy sales was primarily due to Hurricane Nate, which negatively impacted several large industrial customers in 2017.

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 negatively impacted several large industrial customers.

See "Operating Revenues" above for a discussion of significant changes in wholesale revenues to affiliated companies.

Fuel and Purchased Power Expenses

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, Mississippi Power purchases a portion of its electricity needs from the wholesale market.

Details of Mississippi Power's generation and purchased power were as follows:

	2018	2017	2016
Total generation *(in millions of KWHs)*	**15,966**	15,319	14,514
Total purchased power *(in millions of KWHs)*(*)	**1,210**	724	1,098
Sources of generation *(percent)* –			
Gas	**93**	92	91
Coal	**7**	8	9
Cost of fuel, generated *(in cents per net KWH)* –			
Gas	**2.65**	2.69	2.41
Coal	**3.50**	3.64	3.91
Average cost of fuel, generated *(in cents per net KWH)*	**2.72**	2.77	2.55
Average cost of purchased power *(in cents per net KWH)*(*)	**3.39**	3.50	3.07

(*) Adjusted to include the impacts of station service in 2018 and test period energy produced in 2017 and 2016 for the Kemper County energy facility, which was accounted for in accordance with FERC guidance.

Fuel and purchased power expenses were $446 million in 2018, an increase of $26 million, or 6.2%, as compared to the prior year. The increase was primarily due to a $35 million increase in KWHs generated and purchased, partially offset by a $9 million decrease in the average cost of generation and purchased power.

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 energy transactions do not have a significant impact on earnings, since energy expenses are generally offset by energy revenues through Mississippi Power'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 $10 million, or 2.5%, in 2018 compared to 2017 primarily due to a 5.2% increase in KWHs generated from gas generation. Fuel expense increased $52 million, or 15.2%, in 2017 compared to 2016 primarily due to an 11.6% higher cost of natural gas.

Purchased Power

Purchased power expense increased $16 million, or 64.0%, in 2018 compared to 2017. The increase was primarily the result of a 67% increase in the volume of KWHs purchased. Purchased power expense decreased $9 million, or 26.5%, in 2017 compared to 2016. The decrease was primarily the result of a 34% decrease in the volume of KWHs purchased, offset by a 13.9% increase in the average cost per KWH purchased compared to 2016. The changes in the volume of KWHs purchased primarily reflect the impact of test period energy offsets in 2017.

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 increased $22 million, or 7.6%, in 2018 compared to the prior year. The increase was primarily due to a $15 million increase related to an employee attrition plan, a $12 million increase in planned generation outage cost, and a $7 million increase related to overhead line maintenance and vegetation management. These increases were partially offset by the deferral of $4 million of compensation costs in accordance with the PEP Settlement Agreement. See Note 2 to the financial statements under "Mississippi Power – Performance Evaluation Plan" for additional information.

Other operations and maintenance expenses decreased $26 million, or 8.2%, 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.

Depreciation and Amortization

Depreciation and amortization increased $8 million, or 5.0%, in 2018 compared to 2017 primarily due to $8 million of amortization related to the ECO Plan and $6 million of depreciation for additional plant in service. These increases were partially offset by a decrease of $4 million in amortization of regulatory assets associated with Mercury and Air Toxics Standards (MATS) rule compliance.

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 amortization of regulatory assets associated with MATS rule compliance.

See Note 5 to the financial statements under "Depreciation and Amortization" and Note 2 to the financial statements under "FERC Matters" and "Mississippi Power – Environmental Compliance Overview Plan" for additional information.

Estimated Loss on Kemper IGCC

In 2018, 2017, and 2016, charges of $37 million, $3.36 billion, and $428 million, respectively, associated with the Kemper IGCC were recorded. The 2018 pre-tax charge of $37 million primarily resulted from the abandonment and related closure activities and ongoing period costs, net of sales proceeds, for the mine and gasifier-related assets at the Kemper County energy facility. In June 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 grants awarded to the project by the DOE under the Clean Coal Power Initiative Round 2 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).

See Note 2 to the financial statements under "Kemper County Energy Facility" for additional information.

Allowance for Equity Funds Used During Construction

AFUDC equity decreased $72 million, or 100.0%, in 2018 as compared to 2017 and $52 million, or 41.9%, in 2017 as compared to 2016 as a result of suspending construction of the Kemper IGCC in June 2017. See Note 2 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 $34 million, or 81.0%, in 2018 compared to 2017. The increase was primarily associated with a $33 million net reduction in interest recorded in 2017 following a settlement with the IRS related to research and experimental (R&E) deductions. The increase also reflects a $29 million reduction in interest capitalized as a result of suspending construction of the Kemper IGCC in June 2017, offset by decreases of $12 million in interest expense as a result of lower average outstanding debt, $8 million related to uncertain tax positions, and $7 million due to the completion of Kemper IGCC carrying cost amortization in 2017.

Interest expense, net of amounts capitalized decreased $32 million, or 43.2%, in 2017 compared to 2016. The decrease was primarily associated with a $33 million net reduction in interest following a settlement with the IRS related to R&E deductions. Also contributing to the decrease was the amortization of $6 million in interest deferrals in accordance with an order the Mississippi PSC issued in December 2015 (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 as a result of suspending construction of the Kemper IGCC.

See Note 10 to the financial statements under "Section 174 Research and Experimental Deduction" for additional information.

Other Income (Expense), Net

Other income (expense), net increased $16 million in 2018 compared to 2017. The increase primarily reflects the $24 million settlement of Mississippi Power's Deepwater Horizon claim in May 2018, partially offset by a $7 million increase in charitable donations. See Note 3 to the financial statements under "General Litigation Matters – Mississippi Power" for additional information. Other income (expense), net increased $3 million in 2017 compared to 2016.

Income Taxes (Benefit)

Income tax benefits decreased $430 million, or 80.8%, in 2018 compared to 2017 primarily due to a $1.07 billion increase in income tax expense from higher pre-tax earnings primarily due to lower charges related to the Kemper County energy facility, net of the non-deductible AFUDC equity portion. This increase in income tax expense was partially offset by a $434 million decrease in income tax expense due to the impacts of the Tax Reform Legislation, including $407 million primarily associated with the revaluation of 2017 deferred tax assets related to the Kemper IGCC recorded in 2017 and $23 million associated with the lower federal income tax rate applicable in 2018, as well as $194 million related to the reduction in 2018 of a valuation allowance for a state income tax NOL carryforward recorded in 2017.

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 10 to the financial statements for additional information.

Effects of Inflation

Mississippi Power 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 Mississippi Power's results of operations has not been substantial in recent years.

FUTURE EARNINGS POTENTIAL

General

Mississippi Power 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 Mississippi Power 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 2 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 Mississippi Power's future earnings depends on numerous factors that affect the opportunities, challenges, and risks of Mississippi Power's business of providing electric service. These factors include Mississippi Power'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 continued customer growth and the weak pace of growth in electricity use per customer, especially in residential and commercial markets. 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 Mississippi Power'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.

Mississippi Power's retail base rates are set under the PEP, a rate plan approved by the Mississippi PSC. Typically, 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. Pursuant to the PEP Settlement Agreement, PEP proceedings are suspended until after the conclusion of the Mississippi Power 2019 Base Rate Case and Mississippi Power is not required to make any PEP filings for regulatory years 2018, 2019, and 2020. See "Retail Regulatory Matters" herein and Note 2 to the financial statements under "Mississippi Power – Performance Evaluation Plan" for more information.

On October 2, 2018, the Mississippi PSC approved the executed agreements between Mississippi Power and its largest retail customer, Chevron, for Mississippi Power to continue providing retail service to the Chevron refinery in Pascagoula, Mississippi

through 2038. The new agreements are not expected to have a material impact on Mississippi Power's earnings; however, the co-generation assets located at the refinery are accounted for as a sales-type lease in accordance with the new lease accounting rules that became 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.

Mississippi Power 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 17.3% of Mississippi Power's total operating revenues in 2018 and are generally subject to 10-year rolling 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

Mississippi Power'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. Mississippi Power maintains comprehensive environmental compliance and GHG strategies to assess upcoming requirements and compliance costs associated with these environmental laws and regulations. The costs, including capital expenditures, operations and maintenance costs, and costs reflected in ARO liabilities, required to comply with environmental laws and regulations and to achieve stated goals may impact future electric generating unit retirement and replacement decisions, results of operations, cash flows, and/or financial condition. Related costs may result from the installation of additional environmental controls, closure and monitoring of CCR facilities, unit retirements, or changing fuel sources for certain existing units, as well as related upgrades to Mississippi Power's transmission and distribution systems. A major portion of these costs is expected to be recovered through retail and wholesale rates. The ultimate impact of environmental laws and regulations and the GHG goals discussed herein will depend on various factors, such as state adoption and implementation of requirements, the availability and cost of any deployed technology, fuel prices, and the outcome of pending and/or future legal challenges.

New or revised environmental laws and regulations could affect many areas of Mississippi Power'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 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/or 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 2 to the financial statements under "Mississippi Power – Environmental Compliance Overview Plan" for additional information.

Through 2018, Mississippi Power has invested approximately $654 million in environmental capital retrofit projects to comply with environmental requirements, with annual totals of approximately $11 million, $9 million, and $17 million for 2018, 2017, and 2016, 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, Mississippi Power's current compliance strategy estimates capital expenditures of $73 million from 2019 through 2023, with annual totals of approximately $18 million, $20 million, $17 million, $5 million, and $13 million for 2019, 2020, 2021, 2022, and 2023, respectively. These estimates do not include any potential compliance costs associated with pending regulation of CO_2 emissions from fossil fuel-fired electric generating units. See "Global Climate Issues" herein for additional information. Mississippi Power also anticipates expenditures associated with ash pond closure and ground water monitoring under the CCR Rule, which are reflected in Mississippi Power's ARO liabilities. See FINANCIAL CONDITION AND LIQUIDITY – "Capital Requirements and Contractual Obligations" herein and Note 6 to the financial statements 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) to protect and improve the nation's air quality, which it reviews and revises periodically. Following a NAAQS revision, states are required to develop an EPA-approved plan to protect air quality. These state plans 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 electric generating facilities. All areas within Mississippi Power's service territory have been designated as attainment for all NAAQS. If 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) to address impacts of SO_2 and NO_X emissions from fossil fuel-fired electric generating plants. CSAPR establishes emissions trading programs and budgets for certain states and allocates emissions allowances for sources in those states. In 2016, the EPA published a final rule establishing more stringent ozone season NO_X emissions budgets in Alabama and Mississippi. The outcome of ongoing CSAPR litigation concerning the 2016 CSAPR rule, to which Mississippi Power is a party, could have an impact on the State of Mississippi's ozone season NO_X emissions budget. Increases in either future fossil fuel-fired generation or the availability or cost of CSAPR allowances could have a negative financial impact on results of operations for Mississippi Power.

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 demonstrating continued reasonable progress towards achieving visibility improvement goals. These plans could require reductions in certain pollutants, such as particulate matter, SO_2, and NO_X, which could result in increased compliance costs. The EPA issued a limited approval of the regional progress SIP for the State of Mississippi because Mississippi must revise the best available retrofit technology (BART) provisions of its SIP. Therefore, Plant Daniel continues to be evaluated under the regional haze BART provisions. Mississippi Power is required to submit Plant Daniel's BART analysis to the State of Mississippi by summer 2019. Requirements for further reduction of these pollutants at Plant Daniel could increase compliance costs.

Water Quality

In 2014, the EPA finalized requirements under Section 316(b) of the Clean Water Act (CWA) to regulate cooling water intake structures (CWIS) to minimize their effects on fish and other aquatic life at existing power plants (e.g. coal, natural gas, oil, and nuclear generating plants) and manufacturing facilities. The regulation requires plant-specific studies to determine applicable CWIS changes to protect organisms that either get caught on the intake screens (impingement) or are drawn into the cooling system (entrainment). Mississippi Power is conducting these studies and currently anticipates applicable CWIS changes may include fish-friendly CWIS screens with fish return systems and minor additions of monitoring equipment at certain plants. However, the ultimate impact of this rule will depend on the outcome of these plant-specific studies, any additional protective measures required to be incorporated into each plant's National Pollutant Discharge Elimination System (NPDES) permit based on site-specific factors, and the outcome of any legal challenges.

In 2015, the EPA finalized the steam electric effluent limitations guidelines (ELG) rule (2015 ELG Rule) that set national standards for wastewater discharges from new and existing steam electric generating units generating greater than 50 MWs. The 2015 ELG Rule prohibits effluent discharges of certain waste streams and imposes stringent limits on flue gas desulfurization (scrubber) wastewater discharges. The revised technology-based limits and the CCR Rule require extensive changes to existing ash and wastewater management systems or the installation and operation of new ash and wastewater management systems. Compliance with the 2015 ELG Rule is expected to require capital expenditures and increased operational costs primarily for Mississippi Power's coal-fired electric generation. State environmental agencies will incorporate specific compliance applicability dates in the NPDES permitting process for each ELG waste stream no later than December 31, 2023. The EPA is scheduled to issue a new rulemaking by December 2019 that could revise the limitations and applicability dates of two of the waste streams regulated in the 2015 ELG Rule. The impact of any changes to the 2015 ELG Rule will depend on the content of the new rule and the outcome of any legal challenges.

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, canals, and wastewater treatment ponds), which could impact new generation projects and permitting and reporting requirements associated with the installation, expansion, and maintenance of transmission and distribution projects. The EPA and the Corps are expected to publish a final rule in 2019 to replace the 2015 WOTUS definition. The impact of any changes to the 2015 WOTUS rule will depend on the content of this final rule and the outcome of any legal challenges.

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 (ash ponds) at active generating power plants. The EPA's CCR Rule requires landfills and ash ponds to be evaluated against a set of performance criteria and potentially closed if minimum criteria are not met. Closure of existing landfills and ash ponds could require installation of equipment and infrastructure to manage CCR in accordance with the CCR Rule. Based on cost estimates for closure and monitoring of landfills and ash ponds pursuant to the CCR Rule, Mississippi

Power recorded AROs for each CCR unit in 2015. As further analysis was performed and closure details were developed, Mississippi Power has continued to periodically update these cost estimates, as discussed further below.

The EPA published certain amendments to the CCR Rule, which became effective August 29, 2018. These amendments extend the date from April 2019 to October 31, 2020 to cease sending CCR and other waste streams to ash ponds that demonstrate compliance with all except two of the specified performance criteria.

On August 21, 2018, the U.S. Court of Appeals for the District of Columbia Circuit issued a decision suggesting the EPA should regulate previously-excluded inactive ash ponds located at retired generation facilities and questioning both the ability of unlined ash ponds to continue operating no matter the performance criteria results and the classification of clay-lined landfills and ash ponds. These developments could impact the expected timing of Mississippi Power's landfill and ash pond closure activities, but the extent of any impact will depend on the outcome of ongoing litigation, anticipated EPA rulemaking action to establish further guidance, and the outcome of any legal challenges.

During 2018, Mississippi Power recorded increases of approximately $16 million to its AROs related to the CCR Rule. The increases include approximately $11 million based on information from feasibility studies performed on an ash pond at Plant Greene County, which is co-owned with Alabama Power, and approximately $5 million related to increases in post-closure care for Plant Watson's ash pond and landfill. The Alabama Power studies for Plant Greene County indicated that additional closure costs, primarily related to increases in estimated ash volume, water management requirements, and design revisions, will be required to close the ash pond under the planned closure-in-place methodology. As the level of work becomes more defined in the next 12 months, it is likely that these cost estimates will change and the change could be material. Mississippi Power expects to periodically update its ARO cost estimates.

In 2016, the Mississippi PSC granted a CPCN to Mississippi Power authorizing certain projects associated with complying with the CCR Rule. Additionally in this order, the Mississippi PSC also authorized Mississippi Power to recover any costs associated with the CPCN, including future monitoring costs, through the ECO clause. Absent continued recovery of ARO costs through regulated rates, Mississippi Power's results of operations, cash flows, and financial condition could be materially impacted. See FINANCIAL CONDITION AND LIQUIDITY – "Capital Requirements and Contractual Obligations" herein and Note 6 to the financial statements for additional information regarding Mississippi Power's AROs.

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

Environmental Remediation

Mississippi Power 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, Mississippi Power may also incur substantial costs to clean up affected sites. Mississippi Power has authority from the Mississippi PSC to recover approved environmental compliance costs through established regulatory mechanisms. Mississippi Power recognizes a liability for environmental remediation costs only when it determines a loss is probable and reasonably estimable.

Global Climate Issues

On August 31, 2018, the EPA published a proposed rule known as the Affordable Clean Energy (ACE) Rule, which is intended to replace a regulation enacted in 2015 known as the Clean Power Plan (CPP), that would limit CO_2 emissions from existing fossil fuel-fired electric generating units. The CPP has been stayed by the U.S. Supreme Court since 2016. The ACE Rule would require states to develop GHG unit-specific emission rate standards based on heat-rate efficiency improvements for existing fossil fuel-fired steam units. As proposed, combustion turbines, including natural gas combined cycles, are not affected sources. As of January 1, 2019, Mississippi Power has ownership interests in six fossil fuel-fired steam units to which the proposed ACE Rule is applicable. The ultimate impact of this rule to Mississippi Power is currently unknown and will depend on changes between the proposal and the final rule, subsequent state plan developments and requirements, and any associated legal challenges.

On December 20, 2018, the EPA published a proposed review of the Standards of Performance for Greenhouse Gas Emissions from New, Modified, and Reconstructed Stationary Sources: Electric Utility Generating Units final rule (2015 NSPS rule). The EPA's final 2015 NSPS rule set standards of performance for new, modified, and reconstructed electric utility generating units which included stationary combustion turbines and fossil-fired steam boilers. This proposal reduces the stringency of the 2015 NSPS rule by not basing the new and reconstructed fossil-fired steam boiler and IGCC standards on partial carbon capture and sequestration. The impact of any changes to this rule will depend on the content of the final rule and the outcome of any legal challenges.

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, Mississippi

Power's 2017 GHG emissions were approximately 8 million metric tons of CO_2 equivalent. The preliminary estimate of Mississippi Power's 2018 GHG emissions on the same basis is approximately 8 million metric tons of CO_2 equivalent.

Through 2017, the Southern Company system has achieved an estimated GHG emission reduction of 36% since 2007. In April 2018, Southern Company established an intermediate goal of a 50% reduction in carbon emissions from 2007 levels by 2030 and a long-term goal of low- to no-carbon operations by 2050. To achieve these goals, the Southern Company system expects to continue growing its renewable energy portfolio, optimize technology advancements to modernize its transmission and distribution systems, increase the use of natural gas for generation, complete ongoing construction projects, invest in energy efficiency, and continue research and development efforts focused on technologies to lower GHG emissions. The Southern Company system's ability to achieve these goals also will be dependent on many external factors, including supportive national energy policies, low natural gas prices, and the development, deployment, and advancement of relevant energy technologies.

FERC Matters

Municipal and Rural Associations Tariff

Mississippi Power 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 2016, Mississippi Power 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 included (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, which totaled approximately $22 million through the suspension of Kemper IGCC start-up activities.

Mississippi Power expects to reach a subsequent settlement agreement with its wholesale customers and will make a filing with the FERC during the first quarter 2019. The settlement agreement is intended to be consistent with the Kemper Settlement Agreement, including the impact of the Tax Reform Legislation. The ultimate outcome of this matter cannot be determined at this time.

In September 2017, Mississippi Power and Cooperative Energy executed a Shared Service Agreement (SSA), as part of the MRA tariff, under which Mississippi Power 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 in October 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 Mississippi Power'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 Mississippi Power's revenues is not expected to be significant through 2020.

Fuel Cost Recovery

Mississippi Power has a wholesale MRA and a Market Based (MB) fuel cost recovery factor. Effective with the first billing cycle for January 2018, fuel rates increased $11 million annually for wholesale MRA customers and $1 million annually for wholesale MB customers. Effective January 1, 2019, the wholesale MRA fuel rate decreased $16 million annually and the wholesale MB fuel rate decreased by an immaterial amount. At December 31, 2018, over recovered wholesale MRA fuel costs included in other regulatory liabilities, current on the balance sheet were approximately $6 million compared to an immaterial amount at December 31, 2017. Under recovered wholesale MB fuel costs included in the balance sheets were immaterial at December 31, 2018 and 2017.

Mississippi Power'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 Mississippi Power's revenues or net income, but will affect cash flow.

Open Access Transmission Tariff

On May 10, 2018, AMEA and Cooperative Energy filed with the FERC a complaint against SCS and the traditional electric operating companies (including Mississippi Power) claiming that the current 11.25% base ROE used in calculating the annual transmission revenue requirements of the traditional electric operating companies' (including Mississippi Power's) open access transmission tariff is unjust and unreasonable as measured by the applicable FERC standards. The complaint requested that the base ROE be set no higher than 8.65% and that the FERC order refunds for the difference in revenue requirements that results from applying a just and reasonable ROE established in this proceeding upon determining the current ROE is unjust and unreasonable. On June 18, 2018, SCS and the traditional electric operating companies (including Mississippi Power) filed their response challenging the adequacy of the showing presented by the complainants and offering support for the current ROE. On September 6, 2018, the FERC issued an order establishing a refund effective date of May 10, 2018 in the event a refund is due and initiating an investigation and settlement procedures regarding the current base ROE. Through December 31, 2018, the estimated maximum potential refund is not expected to be material to Mississippi Power's results of operations or cash flows. The ultimate outcome of this matter cannot be determined at this time.

Cooperative Energy Power Supply Agreement

In 2008, Mississippi Power 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, Mississippi Power and Cooperative Energy executed an amendment to extend the PSA through March 31, 2021, effective April 1, 2018, which increased total capacity by 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 Mississippi Power's transmission system that became effective in 2011. As a result of the PSA amendment, Cooperative Energy and SCS amended the terms of the NITSA, which the FERC approved, to provide for the purchase of incremental transmission capacity for service beginning April 1, 2018 through March 31, 2021.

Retail Regulatory Matters

Mississippi Power's rates and charges for service to retail customers are subject to the regulatory oversight of the Mississippi PSC. Mississippi Power'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 Mississippi Power's base rates. See Note 2 to the financial statements under "Mississippi Power" for additional information.

Operations Review

In August 2018, the Mississippi PSC began an operations review of Mississippi Power, for which the final report is expected prior to the conclusion of the Mississippi Power 2019 Base Rate Case. Mississippi Power expects that the review will include, but not be limited to, a comparative analysis of its costs, its cost recovery framework, and ways in which it may streamline management operations for the reasonable benefit of ratepayers. The ultimate outcome of this matter cannot be determined at this time.

Performance Evaluation Plan

Mississippi Power's retail base rates generally 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, Mississippi Power 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 Mississippi Power's PEP lookback filing for 2011. In 2013, the MPUS contested Mississippi Power's PEP lookback filing for 2012, which indicated a refund due to customers of $5 million. In 2014 through 2018, Mississippi Power submitted its annual PEP lookback filings for the prior years, which for each of 2013, 2014, and 2017 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 in November 2017, Mississippi Power 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, Mississippi Power revised its annual projected PEP filing for 2018 to reflect the impacts of the Tax Reform Legislation. The revised filing requested an increase of $26 million in annual revenues, based on a performance adjusted ROE of 9.33% and an increased equity ratio of 55%. On July 27, 2018, Mississippi Power and the MPUS entered into the PEP Settlement Agreement, which was approved by the Mississippi PSC on August 7, 2018. Rates under the PEP Settlement Agreement became effective with the first billing cycle of September 2018. The PEP Settlement Agreement provides for an increase of approximately $21.6 million in annual base retail revenues, which excludes certain compensation costs contested by the MPUS, as well as approximately $2 million which was subsequently approved for recovery through the 2018 Energy Efficiency Cost Rider as discussed below. Under the PEP Settlement Agreement, Mississippi Power is deferring the contested compensation costs for 2018 and 2019 as a regulatory asset, which totaled $4 million as of December 31, 2018 and is included in other regulatory assets, deferred on the balance sheet. The Mississippi PSC is currently expected to rule on the appropriate treatment for such costs in connection with the Mississippi Power 2019 Base Rate Case. The ultimate outcome of this matter cannot be determined at this time.

Pursuant to the PEP Settlement Agreement, Mississippi Power's performance-adjusted allowed ROE is 9.31% and its allowed equity ratio is capped at 51%, pending further review by the Mississippi PSC. In lieu of the requested equity ratio increase, Mississippi Power retained $44 million of excess accumulated deferred income taxes resulting from the Tax Reform Legislation until the conclusion of the Mississippi Power 2019 Base Rate Case. Further, Mississippi Power agreed to seek equity contributions sufficient to restore its equity ratio to 50% by December 31, 2018. Since Mississippi Power's actual average equity ratio for 2018 was more than 1% lower than the 50% target, Mississippi Power deferred the corresponding difference in its revenue requirement of approximately $4 million as a regulatory liability for resolution in the Mississippi Power 2019 Base Rate Case. Pursuant to the PEP Settlement Agreement, PEP proceedings are suspended until after the conclusion of the Mississippi Power 2019 Base Rate Case and Mississippi Power is not required to make any PEP filings for regulatory years 2018, 2019, and 2020. The PEP Settlement Agreement also resolved all open PEP filings with no change to customer rates. As a result, in the third quarter 2018, Mississippi Power recognized revenues of $5 million previously reserved in connection with the 2012 PEP lookback filing.

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 May 8, 2018, the Mississippi PSC issued an order approving Mississippi Power's revised annual projected Energy Efficiency Cost Rider 2018 compliance filing, which increased annual retail revenues by approximately $3 million effective with the first billing cycle for June 2018.

On February 5, 2019, the Mississippi PSC issued an order approving Mississippi Power's Energy Efficiency Cost Rider 2019 compliance filing, which included a slight decrease in annual retail revenues, effective with the first billing cycle in March 2019.

Environmental Compliance Overview Plan

In accordance with a 2011 accounting order from the Mississippi PSC, Mississippi Power 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 the fuel conversion of 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 Mississippi Power's financial statements.

In August 2016, the Mississippi PSC approved Mississippi Power'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.

In May 2017, the Mississippi PSC approved Mississippi Power'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, plus carrying costs, of related revenue requirements in excess of the 2% maximum was deferred for inclusion in the 2018 filing.

On February 14, 2018, Mississippi Power submitted its ECO Plan filing for 2018, including the effects of the 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.

On August 3, 2018, Mississippi Power and the MPUS entered into the ECO Settlement Agreement, which provides for an increase of approximately $17 million in annual base retail revenues and was approved by the Mississippi PSC on August 7, 2018. Rates under the ECO Settlement Agreement became effective with the first billing cycle of September 2018 and will continue in effect until modified by the Mississippi PSC. These revenues are expected to be sufficient to recover the costs included in Mississippi Power's request for 2018, as well as the remaining deferred amounts, totaling $26 million at December 31, 2018, along with the related carrying costs. In accordance with the ECO Settlement Agreement, ECO Plan proceedings are suspended until after the conclusion of the Mississippi Power 2019 Base Rate Case and Mississippi Power is not required to make any ECO Plan filings for 2018, 2019, and 2020, with any necessary adjustments to be reflected in the Mississippi Power 2019 Base Rate Case. The ECO Settlement Agreement contains the same terms as the PEP Settlement Agreement described herein with respect to allowed ROE and equity ratio. At December 31, 2018, Mississippi Power has recorded $2 million in other regulatory liabilities, deferred on the balance sheet related to the actual December 31, 2018 average equity ratio differential from target applicable to the ECO Plan.

Fuel Cost Recovery

Mississippi Power establishes, annually, a retail fuel cost recovery factor that is approved by the Mississippi PSC. Mississippi Power is required to file for an adjustment to the retail fuel cost recovery factor annually. In January 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 $55 million. On January 16, 2018, the Mississippi PSC approved the 2018 retail fuel cost recovery factor, effective February 2018 through January 2019, which resulted in an annual revenue increase of $39 million. At December 31, 2018, the amount of over recovered retail fuel costs included in the balance sheet in other accounts payable was approximately $8 million compared to $6 million under recovered at December 31, 2017. On January 10, 2019, the Mississippi PSC approved the 2019 retail fuel cost recovery factor, effective February 2019, which results in a $35 million decrease in annual revenues as a result of lower expected fuel costs.

Mississippi Power'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 Mississippi Power's revenues or net income but will affect operating cash flows.

Ad Valorem Tax Adjustment

Mississippi Power establishes annually an ad valorem tax adjustment factor that is approved by the Mississippi PSC to collect the ad valorem taxes paid by Mississippi Power. On May 8, 2018, the Mississippi PSC approved Mississippi Power's annual ad valorem tax adjustment factor filing for 2018, which included a rate increase of 0.8%, or $7 million, effective with the first billing cycle for June 2018.

Kemper County Energy Facility

Overview

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

Schedule and Cost Estimate

In 2012, the Mississippi PSC issued an order (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. Mississippi Power placed the combined cycle and the associated common facilities portion of the Kemper County energy facility in service in August 2014. The combined cycle and associated common facilities portions of the Kemper County energy facility were dedicated as Plant Ratcliffe on April 27, 2018.

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. The order established the 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 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 received in April 2016 (Additional DOE Grants). 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 gasification 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.

In 2018, Mississippi Power recorded pre-tax charges to income of $37 million ($27 million after tax), primarily resulting from the abandonment and related closure activities and ongoing period costs, net of sales proceeds, for the mine and gasifier-related assets at the Kemper County energy facility. In addition, Mississippi Power recorded a credit to earnings of $95 million in the fourth quarter 2018 primarily resulting from the reduction of a valuation allowance for a state income tax NOL carryforward associated with the Kemper County energy facility. Additional closure costs for the mine and gasifier-related assets, currently estimated at up to $10 million pre-tax (excluding salvage, net of dismantlement costs), may be incurred through the first half of 2020. In addition, period costs, including, but not limited to, costs for compliance and safety, ARO accretion, and property taxes for the mine and gasifier-related assets, are estimated to total $11 million in 2019 and $2 million to $4 million annually in 2020 through 2023. Mississippi Power is currently evaluating its options regarding the final disposition of the CO_2 pipeline, including removal of the pipeline. This evaluation is expected to be complete later in 2019. If Mississippi Power ultimately decides to remove the CO_2 pipeline, the cost of removal would have a material impact on Mississippi Power's financial statements. The ultimate outcome of these matters cannot be determined at this time.

See Note 10 to the financial statements for additional information.

Rate Recovery

Kemper Settlement Agreement

In 2015, the Mississippi PSC issued the In-Service Asset Rate Order regarding the Kemper County energy facility assets that were commercially operational and 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 which went into effect on December 17, 2015.

On February 6, 2018, the Mississippi PSC voted to approve the Kemper Settlement Agreement, which resolved all cost recovery issues, modified the CPCN to limit the Kemper County energy facility to natural gas combined cycle operation, and provided for an annual revenue requirement of approximately $99.3 million for costs related to the Kemper County energy facility, which included the impact of the 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 reflect a reduction of approximately $26.8 million annually, effective with the first billing cycle of April 2018, and include no recovery for costs associated with the gasifier portion of the Kemper County energy facility in 2018 or at any future date.

Reserve Margin Plan

On August 6, 2018, Mississippi Power filed its proposed Reserve Margin Plan (RMP), as required by the Mississippi PSC's order in the Kemper Settlement Docket. Under the RMP, Mississippi Power proposed alternatives that would reduce its reserve margin, with the most economic of the alternatives being the two-year and seven-year acceleration of the retirement of Plant Watson Units 4 and 5, respectively, to the first quarter 2022 and the four-year acceleration of the retirement of Plant Greene County Units 1 and 2 to the third quarter 2021 and the third quarter 2022, respectively, in order to lower or avoid operating costs. The Plant Greene County unit retirements would require the completion by Alabama Power of proposed transmission and system reliability improvements, as well as agreement by Alabama Power. The RMP filing also states that, in the event the Mississippi PSC ultimately approves an alternative that includes an accelerated retirement, Mississippi Power would require authorization to defer in a regulatory asset for future recovery the remaining net book value of the units at the time of retirement. A decision by the Mississippi PSC that does not include recovery of the remaining book value of any generating units retired could have a material impact on Mississippi Power's financial statements. The ultimate outcome of this matter cannot be determined at this time.

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. As a result of the abandonment of the Kemper IGCC, final mine reclamation began in 2018 and is expected to be substantially completed in 2020, with monitoring expected to continue through 2027. See Note 6 to the financial statements and Note 7 to the financial statements under "Mississippi Power" for additional information.

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. The agreement with Denbury was terminated in December 2018 and did not have a material impact on Mississippi Power's results of operations. Mississippi Power is currently evaluating its options regarding the final disposition of the CO_2 pipeline, including removal of the pipeline. This evaluation is expected to be complete later in 2019. If Mississippi Power ultimately decides to remove the CO_2 pipeline, the cost of removal would have a material impact on Mississippi Power's financial statements. The ultimate outcome of this matter cannot be determined at this time.

For additional information on the Kemper County energy facility, see Note 2 to the financial statements under "Mississippi Power – Kemper County Energy Facility."

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. Through December 31, 2018, Mississippi Power received total DOE grants of $387 million, of which $382 million reduced the construction costs of the Kemper County energy facility and $5 million reimbursed Mississippi Power for expenses associated with DOE reporting. On December 12, 2018, Mississippi Power filed with the DOE its request for property closeout certification under the contract related to the grants received. Mississippi Power and the DOE are currently in discussions regarding the requested closeout and property disposition, which may require payment to the DOE for a portion of certain property that is to be retained by Mississippi Power. The ultimate outcome of this matter cannot be determined at this time; however, it could have a material impact on Mississippi Power's financial statements.

Income Tax Matters

Federal Tax Reform Legislation

In December 2017, the Tax Reform Legislation was signed into law and became effective on January 1, 2018. The Tax Reform Legislation, among other things, reduced the federal corporate income tax rate to 21%, retained normalization provisions for public utility property and existing renewable energy incentives, and repealed the corporate alternative minimum tax. 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. See Note 10 to the financial statements for information on Southern Company's joint consolidated income tax allocation agreement.

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 provided 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, Mississippi Power considered all amounts recorded in the financial statements as a result of the Tax Reform Legislation "provisional" as discussed in SAB 118 and subject to revision prior to filing its 2017 tax return in the fourth quarter 2018. Mississippi Power recognized tax expense of $372 million in 2017. Following the filing of its 2017 tax return, Mississippi Power recorded tax benefits of $35 million to adjust the provisional amount for a total net tax expense of $337 million as a result of the Tax Reform Legislation. In addition, in total, Mississippi Power recorded an $11 million increase in regulatory assets and a $395 million increase in regulatory liabilities as a result of the Tax Reform Legislation and $1 million of stranded excess deferred tax balances in AOCI at December 31, 2017 were adjusted through retained earnings in 2018. As of December 31, 2018, Mississippi Power considered the measurement of impacts from the Tax Reform Legislation on deferred income tax assets and liabilities, primarily due to the impact of the reduction of the corporate income tax rate, to be complete.

However, the IRS continues to issue regulations that provide further interpretation and guidance on the law and each state's adoption of the provisions contained in the Tax Reform Legislation remains uncertain. 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. The ultimate impact of this matter cannot be determined at this time. See Note 2 to the financial statements for additional information regarding the PEP Settlement Agreement and the ECO Settlement Agreement, which reflect certain impacts of the Tax Reform Legislation. Also see FINANCIAL CONDITION AND LIQUIDITY – "Credit Rating Risk" herein and Note 10 to the financial statements under "Current and Deferred Income Taxes" for additional information.

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 $10 million for the 2018 tax year and Mississippi Power does not expect material positive cash flows from bonus depreciation for the 2019 tax year. See Note 10 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.

Other Matters

Mississippi Power is involved in various other matters being litigated and regulatory matters that could affect future earnings. In addition, Mississippi Power is subject to certain claims and legal actions arising in the ordinary course of business. Mississippi Power's business activities are subject to extensive governmental regulation related to public health and the environment, such as laws and regulations governing air, water, land, and protection of other natural resources. Litigation over environmental issues and claims of various types, including property damage, personal injury, common law nuisance, and citizen enforcement of environmental laws and regulations, 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 Notes 2 and 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 Mississippi Power's financial statements. See Notes 2 and 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.

To mitigate customer rate impacts associated with rising costs and declining sales, Mississippi Power management approved an employee attrition plan on July 13, 2018. In 2018, Mississippi Power recorded $16 million in expenses related to this plan.

On October 2, 2018, the Mississippi PSC approved the executed agreements between Mississippi Power and its largest retail customer, Chevron, for Mississippi Power to continue providing retail service to the Chevron refinery in Pascagoula, Mississippi through 2038. The new agreements are not expected to have a material impact on earnings.

In conjunction with Southern Company's sale of Gulf Power, Mississippi Power and Gulf Power have committed to seek a restructuring of their 50% undivided ownership interests in Plant Daniel such that each of them would, after the restructuring,

own 100% of a generating unit. On January 15, 2019, Gulf Power provided notice to Mississippi Power that Gulf Power will retire its share of the generating capacity of Plant Daniel on January 15, 2024. Mississippi Power has the option to purchase Gulf Power's ownership interest for $1 on January 15, 2024, provided that Mississippi Power exercises the option no later than 120 days prior to that date. Mississippi Power is assessing the potential operational and economic effects of Gulf Power's notice. The ultimate outcome of these matters remains subject to completion of Mississippi Power's evaluations and applicable regulatory approvals, including the FERC and the Mississippi PSC, and cannot now be determined. See Note 15 to the financial statements under "Southern Company's Sale of Gulf Power" for information regarding the sale of Gulf Power.

Litigation

On May 18, 2018, Southern Company and Mississippi Power received a notice of dispute and arbitration demand filed by Martin Product Sales, LLC (Martin) based on two agreements, both related to Kemper IGCC byproducts for which Mississippi Power provided termination notices in September 2017. Martin alleges breach of contract, breach of good faith and fair dealing, fraud and misrepresentation, and civil conspiracy and makes a claim for damages in the amount of approximately $143 million, as well as additional unspecified damages, attorney's fees, costs, and interest. In the first quarter 2019, Mississippi Power and Southern Company filed motions to dismiss.

On November 21, 2018, Ray C. Turnage and 10 other individual plaintiffs filed a putative class action complaint against Mississippi Power and the three current members of the Mississippi PSC in the U.S. District Court for the Southern District of Mississippi. Mississippi Power received Mississippi PSC approval in 2013 to charge a mirror CWIP rate premised upon including in its rate base pre-construction and construction costs for the Kemper IGCC prior to placing the Kemper IGCC into service. The Mississippi Supreme Court reversed that approval and ordered Mississippi Power to refund the amounts paid by customers under the previously-approved mirror CWIP rate. The plaintiffs allege that the initial approval process, and the amount approved, were improper. They also allege that Mississippi Power underpaid customers in the refund process because it applied the wrong interest rate to the payments. The plaintiffs seek to recover, on behalf of themselves and their putative class, actual damages, punitive damages, pre-judgment interest, post-judgment interest, attorney's fees, and costs.

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

See Note 2 to the financial statements under "Kemper County Energy Facility" for additional information.

ACCOUNTING POLICIES

Application of Critical Accounting Policies and Estimates

Mississippi Power prepares its financial statements in accordance with GAAP. Significant accounting policies are described in Notes 1, 5, and 6 to the financial statements. In the application of these policies, certain estimates are made that may have a material impact on Mississippi Power'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

Mississippi Power is subject to retail regulation by the Mississippi PSC and wholesale regulation by the FERC. These regulatory agencies set the rates Mississippi Power is permitted to charge customers based on allowable costs. As a result, Mississippi Power 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 Mississippi Power'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 Mississippi Power; therefore, the accounting estimates inherent in specific costs such as depreciation and pension and other postretirement benefits have less of a direct impact on Mississippi Power's results of operations and financial condition than they would on a non-regulated company.

As reflected in Note 2 to the financial statements under "Mississippi Power – Regulatory Assets and Liabilities," 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 Mississippi Power's financial statements.

Kemper County Energy Facility Closure Costs

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. 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, of which $305 million ($188 million after tax) occurred in 2017 and $428 million ($264 million after tax) occurred in 2016.

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; therefore, Mississippi Power suspended the operation and start-up of the gasifier portion of the Kemper County energy facility on June 28, 2017.

As a result of these events, cost recovery of the gasification 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 gasification 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. The estimated construction costs and project completion date were no longer considered significant accounting estimates for 2017 following the suspension and related charges to earnings. In addition, the Kemper Settlement Agreement was approved by the Mississippi PSC on February 6, 2018 and resolved all related cost recovery issues.

In 2018, Mississippi Power recorded pre-tax charges to income of $37 million ($27 million after tax), primarily resulting from the abandonment and related closure activities and ongoing period costs, net of sales proceeds, for the mine and gasifier-related assets at the Kemper County energy facility. Additional closure costs for the mine and gasifier-related assets, currently estimated at up to $10 million pre-tax (excluding salvage, net of dismantlement costs), may be incurred through the first half of 2020. During the fourth quarter 2018, Mississippi Power began evaluating its options regarding the final disposition of the CO_2 pipeline, including removal of the pipeline. This evaluation is expected to be complete later in 2019. If Mississippi Power ultimately decides to remove the CO_2 pipeline, the cost of removal would have a material impact on Mississippi Power's financial statements. In addition, in December 2018, Mississippi Power filed with the DOE its request for property closeout certification under the contract related to the grants received. Mississippi Power and the DOE are currently in discussions regarding the requested closeout and property disposition, which may require payment to the DOE for a portion of certain property that is to be retained by Mississippi Power and could have a material impact on Mississippi Power's financial statements. Given the significant judgment and uncertainty involved in estimating these remaining costs associated with the abandonment and closure activities for the mine and gasifier-related assets at the Kemper County energy facility, Mississippi Power considers the related liabilities to be critical accounting estimates.

See Note 2 to the financial statements under "Kemper County Energy Facility" for additional information. The ultimate outcome of these matters cannot be determined at this time.

Asset Retirement Obligations

AROs are computed as the fair value of the estimated costs for an asset's future retirement and are recorded in the period in which the liability is incurred. The estimated 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, Mississippi Power has AROs related to various landfill sites, underground storage tanks, water wells, mine reclamation, and asbestos removal.

Mississippi Power 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 retirement obligations will be recognized when sufficient

information becomes available to support a reasonable estimation of the retirement obligation. In 2018, Mississippi Power incurred $16 million in ARO revisions, including $11 million at Plant Greene County, which is co-owned with Alabama Power.

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. Mississippi Power expects to periodically update its ARO cost estimates. See FUTURE EARNINGS POTENTIAL – "Environmental Matters – Environmental Laws and Regulations – Coal Combustion Residuals" herein and Note 6 to the financial statements for additional information.

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

Pension and Other Postretirement Benefits

Mississippi Power'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 Mississippi Power believes that the assumptions used are appropriate, differences in actual experience or significant changes in assumptions would affect its pension and other postretirement benefit costs and obligations.

Key elements in determining Mississippi Power'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 Mississippi Power's liability related to the pension and other postretirement benefit plans, Southern 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.

A 25 basis point change in any significant assumption (discount rate, salary increases, or long-term rate of return on plan assets) would result in a $1 million or less change in total annual benefit expense, a $19 million or less change in the projected obligation for the pension plan, and a $2 million or less change in the projected obligation for other post retirement benefit plans.

See Note 11 to the financial statements for additional information regarding pension and other postretirement benefits.

Contingent Obligations

Mississippi Power 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 Notes 2 and 3 to the financial statements for more information regarding certain of these contingencies. Mississippi Power 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 Mississippi Power's results of operations, cash flows, or financial condition.

Recently Issued Accounting Standards

See Note 1 to the financial statements under "Recently Adopted Accounting Standards" for additional information.

In 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 Mississippi Power adopted the new standard effective January 1, 2019.

Mississippi Power elected the transition methodology provided by ASU No. 2018-11, *Leases (Topic 842): Targeted Improvements*, whereby the requirements of ASU 2016-02 are applied on a prospective basis as of the adoption date of January 1, 2019, without restating prior periods. Mississippi Power elected the package of practical expedients provided by ASU 2016-02

that allows prior determinations of whether existing contracts are, or contain, leases and the classification of existing leases to continue without reassessment. Additionally, Mississippi Power applied the use-of-hindsight practical expedient in determining lease terms as of the date of adoption and elected the practical expedient that allows existing land easements not previously accounted for as leases not to be reassessed. Mississippi Power also made accounting policy elections to account for short-term leases in all asset classes as off-balance sheet leases and combined lease and non-lease components in the computations of lease obligations and right-of-use assets for most asset classes.

Mississippi Power completed the implementation of a new application to track and account for its leases and updated its internal controls and accounting policies to support the accounting for leases under ASU 2016-02. Mississippi Power completed its lease inventory and determined its most significant leases involve equipment and railcar leases. In the first quarter 2019, adoption of ASU 2016-02 did not have a material impact on Mississippi Power's balance sheet or statement of income.

FINANCIAL CONDITION AND LIQUIDITY

Overview

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 2 to the financial statements for additional information.

Mississippi Power's financial condition remained stable at December 31, 2018. Mississippi Power'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 maintain existing generation facilities, to comply with environmental regulations including adding environmental modifications to certain existing generating units and closures of ash ponds, to expand and improve transmission and distribution facilities, and for restoration following major storms. Operating cash flows provide a substantial portion of Mississippi Power's cash needs. For the three-year period from 2019 through 2021, Mississippi Power's projected common stock dividends, capital expenditures, and debt maturities are expected to exceed operating cash flows. Mississippi Power plans to finance future cash needs in excess of its operating cash flows primarily through external securities issuances, borrowings from financial institutions, including commercial paper to the extent Mississippi Power is eligible to participate, and equity contributions from Southern Company. Mississippi Power 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.

Mississippi Power's investments in the qualified pension plan decreased in value as of December 31, 2018 as compared to December 31, 2017. No contributions to the qualified pension plan were made for the year ended December 31, 2018 and no mandatory contributions to the qualified pension plan are anticipated during 2019. See Note 11 to the financial statements under "Pension Plans" for additional information.

Net cash provided from operating activities totaled $804 million for 2018, an increase of $301 million as compared to 2017. The increase in cash provided from operating activities in 2018 was primarily related to increased income tax refunds in 2018 primarily related to the tax abandonment of the Kemper IGCC. 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 Section 174 R&E settlement, largely offset by a decrease in income taxes related to the Kemper County energy facility and the Tax Reform Legislation.

Net cash used for investing activities in 2018, 2017, and 2016 totaled $232 million, $504 million, and $697 million, respectively. The cash used for investing activities in 2018 was primarily due to gross property additions related to other production, distribution, transmission, and steam production. The cash used for investing activities in 2017 and 2016 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.

Net cash used for financing activities totaled $527 million in 2018 primarily due to redemption of preferred stock, long-term debt, short-term borrowings, and senior notes, partially offset by the issuance of senior notes and short-term borrowings. Net cash provided from financing activities totaled $25 million in 2017 primarily from 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.

Significant balance sheet changes in 2018 included increases of $442 million in long-term debt primarily due to the issuance of senior notes, a net change of $475 million in accumulated deferred income taxes primarily due to the tax abandonment of the

Kemper IGCC, and a decrease of $949 million in securities due within one year primarily due to the repayment of a $900 million unsecured term loan. See "Financing Activities" herein and Notes 8 and 10 to the financial statements for additional information.

Mississippi Power's ratio of common equity to total capitalization plus short-term debt was 50% and 39% at December 31, 2018 and 2017, respectively. The increase was primarily due to repayment of debt obligations in 2018. See Note 8 to the financial statements for additional information.

Sources of Capital

Mississippi Power plans to obtain the funds to meet its future capital needs from operating cash flows, external securities issuances, borrowings from financial institutions, including commercial paper to the extent Mississippi Power is eligible to participate, and equity contributions from Southern Company. However, the amount, type, and timing of any future financing, if needed, will depend upon prevailing market conditions, regulatory approval, and other factors.

The issuance of securities by Mississippi Power is subject to regulatory approval by the FERC. Additionally, with respect to the public offering of securities, Mississippi Power files registration statements with the SEC under the Securities Act of 1933, as amended. The amounts of securities authorized by the FERC, as well as the securities registered under the Securities Act of 1933, as amended, 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.

Mississippi Power obtains financing separately without credit support from any affiliate. See Note 8 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 Mississippi Power are not commingled with funds of any other company in the Southern Company system.

Mississippi Power'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, 2018, Mississippi Power had approximately $293 million of cash and cash equivalents. Committed credit arrangements with banks at December 31, 2018 were $100 million, all of which is unused. In October 2018, Mississippi Power amended its one-year credit arrangements in an aggregate amount of $100 million to extend the maturity dates from 2018 to 2019.

See Note 8 to the financial statements under "Bank Credit Arrangements" for additional information.

All of these bank credit arrangements contain covenants that limit debt levels and typically contain cross acceleration provisions to other indebtedness (including guarantee obligations) of Mississippi Power. Such cross-acceleration provisions to other indebtedness would trigger an event of default if Mississippi Power defaulted on indebtedness, the payment of which was then accelerated. At December 31, 2018, Mississippi Power 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, Mississippi Power expects to renew or replace its credit arrangements as needed, prior to expiration. In connection therewith, Mississippi Power may extend the maturity dates and/or increase or decrease the lending commitments thereunder.

A portion of the $100 million unused credit arrangements with banks is allocated to provide liquidity support to Mississippi Power's revenue bonds. The amount of variable rate revenue bonds outstanding requiring liquidity support at December 31, 2018 was approximately $40 million.

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, 2018	**$ —**	**—%**	**$ 68**	**2.0%**	**$ 300**
December 31, 2017	$ 4	3.8%	$ 18	3.0%	$ 36
December 31, 2016	$ 23	2.6%	$ 112	2.0%	$ 500

(*) Average and maximum amounts are based upon daily balances during the 12-month periods ended December 31, 2018, 2017, and 2016.

Mississippi Power believes the need for working capital can be adequately met by utilizing lines of credit, short-term bank notes, commercial paper to the extent Mississippi Power is eligible to participate, and operating cash flows.

Financing Activities

In March 2018, Mississippi Power issued $300 million aggregate principal amount of Series 2018A Floating Rate Senior Notes due March 27, 2020 bearing interest based on three-month LIBOR and $300 million aggregate principal amount of Series 2018B 3.95% Senior Notes due March 30, 2028. In March 2018, Mississippi Power also entered into a $300 million short-term floating rate bank loan bearing interest based on one-month LIBOR, of which $200 million was repaid in the second quarter 2018 and $100 million was repaid in the third quarter 2018. Mississippi Power used the proceeds from these financings to repay a $900 million unsecured floating rate term loan.

In July 2018, Mississippi Power purchased and held approximately $43 million aggregate principal amount of Mississippi Business Finance Corporation Pollution Control Revenue Refunding Bonds, Series 2002. Mississippi Power may reoffer these bonds to the public at a later date.

In October 2018, Mississippi Power completed the redemption of all 334,210 outstanding shares of its preferred stock (as well as related depositary shares), with an aggregate par value of approximately $33.4 million; all $30 million aggregate principal amount outstanding of its Series G 5.40% Senior Notes due July 1, 2035; and all $125 million aggregate principal amount outstanding of its Series 2009A 5.55% Senior Notes due March 1, 2019.

In December 2018, Southern Company made equity contributions totaling $17 million to Mississippi Power.

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

Credit Rating Risk

At December 31, 2018, Mississippi Power 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 2, 2018, the Mississippi PSC approved executed agreements between Mississippi Power and its largest retail customer, Chevron, for Mississippi Power 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 $101 million at December 31, 2018, 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 Mississippi Power'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, 2018, the maximum potential collateral requirements at a rating below BBB- and/or Baa3 equaled approximately $283 million.

Included in these amounts are certain agreements that could require collateral in the event that either Alabama Power or Georgia Power (affiliate companies of Mississippi 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 Mississippi Power to access capital markets and would be likely to impact the cost at which it does so.

On February 26, 2018, Moody's revised its rating outlook for Mississippi Power from stable to positive. On August 8, 2018, Moody's upgraded Mississippi Power's senior unsecured rating to Baa3 from Ba1 and maintained the positive rating outlook.

On February 28, 2018, Fitch removed Mississippi Power from rating watch negative and revised its rating outlook from stable to positive.

On March 14, 2018, S&P upgraded the senior unsecured long-term debt rating of Mississippi Power to A- from BBB+. The outlook remained negative.

As a result of 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 Mississippi Power, may be negatively impacted. The PEP Settlement Agreement is expected to help mitigate these potential adverse impacts by allowing Mississippi Power to retain the excess deferred taxes resulting from the Tax Reform Legislation until the conclusion of the Mississippi Power 2019 Base Rate Case. In addition, Mississippi Power has committed to seek equity contributions sufficient to restore its equity ratio to the 50% target. See Note 2 to the financial statements under "Mississippi Power" for additional information.

Market Price Risk

Due to cost-based rate regulation and other various cost recovery mechanisms, Mississippi Power 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, Mississippi Power nets the exposures, where possible, to take advantage of natural offsets and enters into various derivative transactions for the remaining exposures pursuant to Mississippi Power's policies in areas such as counterparty exposure and risk management practices. Mississippi Power'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, Mississippi Power may enter into derivatives that have been designated as hedges. The weighted average interest rate on $340 million of long-term variable interest rate exposure at December 31, 2018 was 3.32%. If Mississippi Power 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, 2018. See Note 1 to the financial statements under "Financial Instruments" and Note 14 to the financial statements for additional information.

To mitigate residual risks relative to movements in electricity prices, Mississippi Power 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. Mississippi Power 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. Mississippi Power had no material change in market risk exposure for the year ended December 31, 2018 when compared to the year ended December 31, 2017.

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:

	2018 Changes	2017 Changes
	Fair Value	
	(in millions)	
Contracts outstanding at the beginning of the period, assets (liabilities), net	**$ (7)**	$ (7)
Contracts realized or settled	**3**	8
Current period changes(*)	**(2)**	(8)
Contracts outstanding at the end of the period, assets (liabilities), net	**$ (6)**	$ (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 at December 31, 2018 and 2017 were as follows:

	2018	2017
	mmBtu Volume	
	(in millions)	
Natural gas options	**3**	**—**
Natural gas swaps	**60**	**53**
Total hedge volume	**63**	**53**

For natural gas hedges, the weighted average swap contract cost above market prices was approximately $0.10 per mmBtu at December 31, 2018 and $0.14 per mmBtu at December 31, 2017. The options outstanding were immaterial for the reporting periods presented. The costs associated with natural gas hedges are recovered through Mississippi Power's ECM clause.

At December 31, 2018 and 2017, substantially all of Mississippi Power's energy-related derivative contracts were designated as regulatory hedges and were related to Mississippi Power'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.

Mississippi Power 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 13 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, 2018 were as follows:

	Fair Value Measurements December 31, 2018		
	Total Fair Value	Maturity	
		Year 1	Years 2&3
		(in millions)	
Level 1	$ —	$ —	$ —
Level 2	(6)	(2)	(4)
Level 3	—	—	—
Fair value of contracts outstanding at end of period	$ (6)	$ (2)	$ (4)

Mississippi Power is exposed to market price risk in the event of nonperformance by counterparties to the energy-related derivative contracts. Mississippi Power 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, Mississippi Power 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 14 to the financial statements.

Capital Requirements and Contractual Obligations

The construction program of Mississippi Power is currently estimated to total $222 million for 2019, $230 million for 2020, $216 million for 2021, $220 million for 2022, and $184 million for 2023. The construction program includes capital expenditures covered under LTSAs. Estimated capital expenditures to comply with environmental laws and regulations included in these amounts are $18 million, $20 million, $17 million, $5 million, and $13 million for 2019, 2020, 2021, 2022, and 2023, respectively. These estimated expenditures do not include any potential compliance costs associated with pending 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.

Mississippi Power also anticipates costs associated with closure and monitoring of ash ponds in accordance with the CCR Rule, which are reflected in Mississippi Power's ARO liabilities. These costs, which are expected to change and could change materially as underlying assumptions are refined and the cost and the method and timing of compliance activities continue to be evaluated, are currently estimated to be $9 million, $9 million, $12 million, $14 million, and $15 million for the years 2019, 2020, 2021, 2022, and 2023, respectively. See FUTURE EARNINGS POTENTIAL – "Environmental Matters – Environmental Laws and Regulations – Coal Combustion Residuals" herein and Note 6 to the financial statements 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 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 11 to the financial statements, Mississippi Power provides postretirement benefits to substantially all employees and funds trusts to the extent required by the FERC.

Funding requirements related to obligations associated with scheduled maturities of long-term debt, as well as the related interest, derivative obligations, pension and other post-retirement benefit plans, leases, other purchase commitments, and ARO settlements are detailed in the contractual obligations table that follows. See Notes 1, 6, 8, 9, 11, and 14 to the financial statements for additional information.

Contractual Obligations

Contractual obligations at December 31, 2018 were as follows:

	2019	2020-2021	2022-2023	After 2023	Total
			(in millions)		
Long-term debt[a] —					
Principal	$ —	$ 577	$ —	$ 983	$ 1,560
Interest	70	130	80	577	857
Financial derivative obligations[b]	3	5	—	—	8
Operating leases[c]	3	3	2	2	10
Purchase commitments —					
Capital[d]	222	410	352	—	984
Fuel[e]	378	368	199	136	1,081
Long-term service agreements[f]	27	57	70	250	404
Purchased power[g]	11	35	36	435	517
ARO settlements[h]	9	21	29	—	59
Pension and other postretirement benefits plans[i]	8	15	—	—	23
Total	$ 731	$ 1,621	$ 768	$ 2,383	$ 5,503

(a) All amounts are reflected based on final maturity dates. Mississippi Power 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, 2018, as reflected in the statements of capitalization. Fixed rates include, where applicable, the effects of interest rate derivatives employed to manage interest rate risk. For additional information, see Note 8 to the financial statements.

(b) Derivative obligations are for energy-related derivatives. For additional information, see Notes 1 and 14 to the financial statements.

(c) See Note 9 to the financial statements for additional information.

(d) Mississippi Power provides estimated capital expenditures for a five-year period, including capital expenditures associated with environmental regulations. At December 31, 2018, significant purchase commitments were outstanding in connection with the construction program. These amounts exclude capital expenditures covered under LTSAs and estimated capital expenditures for AROs, which are reflected separately. See FUTURE EARNINGS POTENTIAL – "Environmental Matters" 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 NYMEX future prices at December 31, 2018.

(f) LTSAs include price escalation based on inflation indices.

(g) 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 2 and 9 to the financial statements for additional information.

(h) Represents estimated costs for a five-year period associated with closing and monitoring ash ponds in accordance with the CCR Rule, which are reflected in Mississippi Power's ARO liabilities. Material expenditures in future years for ARO settlements also will be required for ash ponds and other liabilities reflected in Mississippi Power's AROs. See FUTURE EARNINGS POTENTIAL – "Environmental Matters – Environmental Laws and Regulations – Coal Combustion Residuals" herein and Note 6 to the financial statements for additional information.

(i) Mississippi Power forecasts contributions to the pension and other postretirement benefit plans over a three-year period. Mississippi Power 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 Mississippi Power's corporate assets. See Note 11 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 Mississippi Power's corporate assets.

OVERVIEW

Business Activities

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 Power continually seeks opportunities to execute its strategy to create value through various transactions including acquisitions, dispositions, and sales of partnership interests, 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. In general, Southern Power commits to the construction or acquisition of new generating capacity only after entering into or assuming long-term PPAs for the new facilities.

During 2018, Southern Power acquired and placed in service the 20-MW Gaskell West 1 solar facility, placed in service the 148-MW Cactus Flats wind facility, acquired and began construction of the 100-MW Wild Horse Mountain and the 200-MW Reading wind facilities, and continued construction of the expansion of the 385-MW Mankato natural gas facility. See FUTURE EARNINGS POTENTIAL – "Acquisitions" and "Construction Projects" herein for additional information.

Also during 2018, Southern Power completed the following sales of noncontrolling interests and sales of assets resulting in approximately $2.6 billion in proceeds:

- On May 22, 2018, Southern Power sold a noncontrolling 33% equity interest in SP Solar, a limited partnership indirectly owning substantially all of Southern Power's solar facilities, for approximately $1.2 billion.
- On December 4, 2018, Southern Power sold all of its equity interests in Plant Oleander and Plant Stanton Unit A (together, the Florida Plants) to NextEra Energy for $203 million.
- On December 11, 2018, Southern Power sold a noncontrolling tax equity interest in SP Wind, a holding company owning a portfolio of eight operating wind facilities, for approximately $1.2 billion.

In addition, on November 5, 2018, Southern Power entered into an agreement to sell all of its equity interests in Plant Mankato (including the 385-MW expansion currently under construction) for an aggregate purchase price of approximately $650 million. The completion of the disposition is subject to the expansion unit reaching commercial operation as well as various other customary conditions to closing, including FERC and state commission approvals, and the sale is expected to close mid-2019. The ultimate outcome of this matter cannot be determined at this time.

At December 31, 2018, Southern Power's generation fleet, which is owned in part with its various partners, totaled 11,888 MWs of nameplate capacity in commercial operation (including 4,508 MWs of nameplate capacity owned by its subsidiaries and including Plant Mankato, which is classified as held for sale in the financial statements). The average remaining duration of Southern Power's total portfolio of wholesale contracts is approximately 14 years, which reduces remarketing risk for Southern Power. With the inclusion of the PPAs and investments associated with renewable and natural gas facilities currently under construction, Southern Power has an average investment coverage ratio, at December 31, 2018, of 93% through 2023 and 91% through 2028 (including Plant Mankato, which is classified as held for sale in the financial statements).

Southern Power's future earnings will be materially decreased as a result of the asset and non-controlling interest sales described above. In addition, 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. In addition, Southern Power's future 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 future tax legislation. See FUTURE EARNINGS POTENTIAL – "General," "Acquisitions," "Construction Projects," and "Income Tax Matters" herein and Notes 10 and 15 to the financial statements for additional information.

To evaluate operating results and to ensure Southern Power's ability to meet its contractual commitments to customers, Southern Power 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 Southern Power's financial performance.

Earnings

Southern Power's 2018 net income was $187 million, an $884 million decrease from 2017, primarily attributable to $743 million of tax benefits recognized in 2017 and $79 million in tax expense recognized in 2018, both related to the Tax Reform Legislation. Also contributing to the decrease were asset impairment charges in 2018 totaling $156 million ($120 million pre-tax for the

Florida Plants and $36 million pre-tax for turbine equipment held for development projects, which together totaled $117 million after tax), partially offset by approximately $65 million in state income tax benefits arising from reorganizations of legal entities that own and operate certain of Southern Power's solar and wind facilities.

Southern Power's 2017 net income was $1.1 billion, a $733 million increase from 2016, primarily attributable to $743 million in tax benefits recognized in 2017 related to the Tax Reform Legislation. Also contributing to the change were increases in operating expenses and interest expense related to Southern Power's growth strategy and continuous construction program, largely offset by increased renewable energy sales.

In addition, tax benefits from wind PTCs significantly impacted Southern Power's net income in 2018 and 2017. Tax benefits from solar ITCs related to the acquisition and construction of new facilities also significantly impacted Southern Power's net income in 2017 and 2016. See Note 10 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	
	2018	2018	2017
		(in millions)	
Operating revenues	**$ 2,205**	**$ 130**	$ 498
Fuel	**699**	**78**	165
Purchased power	**176**	**27**	47
Other operations and maintenance	**395**	**9**	32
Depreciation and amortization	**493**	**(10)**	151
Taxes other than income taxes	**46**	**(2)**	25
Asset impairment	**156**	**156**	—
Gain on disposition	**(2)**	**(2)**	—
Total operating expenses	**1,963**	**256**	420
Operating income	**242**	**(126)**	78
Interest expense, net of amounts capitalized	**183**	**(8)**	74
Other income (expense), net	**23**	**22**	(5)
Income taxes (benefit)	**(164)**	**775**	(744)
Net income	**246**	**(871)**	743
Net income attributable to noncontrolling interests	**59**	**13**	10
Net income attributable to Southern Power	**$ 187**	**$ (884)**	$ 733

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 Southern Power's generation facilities. To the extent Southern Power has capacity not contracted under a PPA, it may sell power into an accessible wholesale market, or, to the extent those generation assets are part of the FERC-approved IIC, it may sell power into the power pool.

Natural Gas and Biomass Capacity and Energy Revenue

Capacity revenues generally represent the greatest contribution to operating 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 Southern Power's customers and their generation capacity, as well as the market prices of wholesale energy compared to the cost of Southern Power'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

Southern Power'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 generated from the respective facility and 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.

See FUTURE EARNINGS POTENTIAL – "Power Sales Agreements" herein for additional information regarding Southern Power's PPAs.

Details of Southern Power's operating revenues were as follows:

	2018	2017	2016
		(in millions)	
PPA capacity revenues	**$ 580**	$ 599	$ 541
PPA energy revenues	**1,140**	970	694
Total PPA revenues	**1,720**	1,569	1,235
Non-PPA revenues	**472**	494	330
Other revenues	**13**	12	12
Total operating revenues	**$ 2,205**	$ 2,075	$ 1,577

Operating revenues for 2018 were $2.2 billion, reflecting a $130 million, or 6%, increase from 2017. The increase in operating revenues was primarily due to the following:

- PPA capacity revenues decreased $19 million, or 3%, primarily due to decreases of $16 million from the contractual expiration of an affiliate natural gas PPA and $5 million from the Florida Plants sold in December 2018.
- PPA energy revenues increased $170 million, or 18%, primarily due to a $142 million increase in sales related to existing natural gas facilities driven by an $88 million increase in the average cost of fuel and a $54 million increase in the volume of KWHs sold due to customer load, a $12 million increase related to PPAs associated with new renewable facilities, and a $16 million increase related to PPAs associated with existing renewable facilities primarily due to an increase in the volume of KWHs sold.
- Non-PPA revenues decreased $22 million, or 4%, primarily due to a $56 million decrease in the volume of KWHs sold from uncovered natural gas capacity through short-term sales, partially offset by a $35 million increase in the market price of energy.

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 Plant Mankato 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 related to 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 market price of energy.

Fuel and Purchased Power Expenses

Details of Southern Power's generation and purchased power were as follows:

	Total KWHs	**Total KWH % Change**	Total KWHs	Total KWH % Change
	2018		2017	
			(in billions of KWHs)	
Generation	**46**		44	
Purchased power	**4**		5	
Total generation and purchased power	**50**	**2%**	49	23%
Total generation and purchased power, excluding solar, wind, and tolling agreements	**29**	**4%**	28	22%

Southern Power's PPAs for natural gas and biomass generation generally provide that the purchasers are responsible for either procuring the fuel (tolling agreements) or reimbursing Southern Power 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. Southern Power 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 Southern Power.

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 Southern Power, an affiliate company, or external parties. Such purchased power costs are generally recovered through PPA revenues.

Details of Southern Power's fuel and purchased power expenses were as follows:

	2018	2017	2016
		(in millions)	
Fuel	**$ 699**	$ 621	$ 456
Purchased power	**176**	149	102
Total fuel and purchased power expenses	**$ 875**	$ 770	$ 558

In 2018, total fuel and purchased power expenses increased $105 million, or 14%, compared to 2017. Fuel expense increased $78 million, or 13%, primarily due to a $60 million increase associated with the volume of KWHs generated, excluding solar, wind, and tolling agreements, primarily due to customer load, and an $18 million increase associated with the average cost of natural gas per KWH generated. Purchased power expense increased $27 million, or 18%, primarily due to a $43 million increase associated with the average cost of purchased power, primarily in the first quarter 2018, partially offset by a $16 million decrease associated with the volume of KWHs purchased.

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, excluding solar, wind, and tolling agreements, 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.

Other Operations and Maintenance Expenses

In 2018, other operations and maintenance expenses increased $9 million, or 2%, compared to 2017. The increase was primarily due to scheduled outage 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 Southern Power's overall growth. These 2017 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.

Depreciation and Amortization

In 2018, depreciation and amortization decreased $10 million, or 2%, compared to 2017, primarily due to the cessation of depreciation on the Florida Plants and Plant Mankato that were classified as held for sale in May and November 2018, respectively. In 2017, depreciation and amortization increased $151 million, or 43%, compared to 2016, primarily due to additional depreciation related to new solar, wind, and natural gas facilities placed in service. See Note 5 to the financial statements under "Depreciation and Amortization – Southern Power" and Note 15 to the financial statements under "Southern Power" and "Assets Held for Sale" for additional information.

Taxes Other Than Income Taxes

In 2018, taxes other than income taxes decreased $2 million, or 4%, compared to 2017. In 2017, taxes other than income taxes were $48 million compared to $23 million in 2016, primarily due to additional property taxes on new facilities.

Asset Impairment

In 2018, asset impairment charges were $156 million. In the second quarter 2018, a $119 million asset impairment charge was recorded in contemplation of the sale of the Florida Plants. In addition, in the third quarter 2018, a $36 million asset impairment charge was recorded on wind turbine equipment held for development projects. There were no asset impairment charges recorded in 2017 or 2016. See Note 15 to the financial statements under "Southern Power – Sales of Natural Gas Plants" and " – Development Projects" for additional information.

Interest Expense, Net of Amounts Capitalized

In 2018, interest expense, net of amounts capitalized decreased $8 million, or 4%, compared to 2017. The decrease was primarily due to an increase in capitalized interest associated with construction projects. 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 Southern Power'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.

Other Income (Expense), Net

In 2018, other income (expense), net increased $22 million compared to 2017 primarily due to a $14 million gain from a joint-development wind project, which is attributable to Southern Power's partner in the project and fully offset within noncontrolling interests. In 2017, other income (expense), net decreased $5 million compared to 2016.

Income Taxes (Benefit)

In 2018, income tax benefit was $164 million compared to $939 million for 2017, a decrease of $775 million, primarily attributable to a $743 million tax benefit in 2017 and a $79 million tax expense in 2018, both related to the remeasurement of accumulated deferred income taxes in accordance with the Tax Reform Legislation. In addition, income tax benefits associated with solar ITCs decreased by $58 million as a result of fewer solar facilities being placed in service in 2018 as compared to 2017. These decreases were partially offset by $65 million of income tax benefits related to certain changes in state apportionment rates arising from reorganizations of Southern Power's legal entities that own and operate certain of its solar and wind facilities and a decrease of $47 million of income tax expense as a result of lower pre-tax earnings and the lower federal tax rate.

In 2017, income tax benefit was $939 million compared to $195 million for 2016 of which $743 million of the increase was related to the Tax Reform Legislation. 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 associated with lower ITCs from solar facilities placed in service.

See FUTURE EARNINGS POTENTIAL – "Income Tax Matters – Federal Tax Reform Legislation" herein and Notes 1 and 10 to the financial statements under "Income and Other Taxes" and "Effective Tax Rate," respectively, for additional information.

Net Income Attributable to Noncontrolling Interests

In 2018, net income attributable to noncontrolling interests increased $13 million, or 28%, compared to 2017. The increase was primarily due to $20 million of net income allocations due to the sale of a noncontrolling 33% equity interest in SP Solar and $14 million of other income allocations attributable to a joint-development wind project, partially offset by a reduction of $19 million due to HLBV income allocations between Southern Power and tax equity partners for partnerships entered into during 2018. In

2017, noncontrolling interests increased $10 million, or 28%, compared to 2016 primarily due to additional net income allocations from new solar partnerships.

Effects of Inflation

Southern Power is party to long-term contracts reflecting market-based rates, including inflation expectations. Any adverse effect of inflation on Southern Power'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 Southern Power's future earnings potential. Southern Power completed multiple sales of noncontrolling interests and assets in 2018 as described below. These sales will materially decrease future earnings and cash flows to Southern Power. See below for a summary of the 2018 disposition activity. The level of Southern Power's future earnings also depends on numerous factors that affect the opportunities, challenges, and risks of Southern Power's competitive wholesale business. These factors include: Southern Power's ability to achieve sales growth while containing costs; regulatory matters; creditworthiness of customers; total generating capacity available in Southern Power's market areas; the successful remarketing of capacity as current contracts expire; and Southern Power's ability to execute its growth strategy through the development or acquisition of renewable facilities and other energy projects.

On May 22, 2018, Southern Power completed the sale of a noncontrolling 33% equity interest in SP Solar, a limited partnership indirectly owning substantially all of Southern Power's solar facilities, to Global Atlantic Financial Group Limited (Global Atlantic) for an aggregate purchase price of approximately $1.2 billion. Accordingly, Global Atlantic will receive 33% of all cash distributions paid by SP Solar. Southern Power continues to consolidate the assets and liabilities of SP Solar with Global Atlantic's share of partnership earnings included in net income attributable to noncontrolling interests in the consolidated statements of income, which was $20 million for the period from May 22, 2018 to December 31, 2018.

Southern Power completed the sale of all of its equity interests in the Florida Plants to NextEra Energy on December 4, 2018, for an aggregate purchase price of $203 million. Pre-tax net income for the Florida Plants was $49 million and $37 million for the period from January 1, 2018 to December 4, 2018 and for the year ended December 31, 2017, respectively.

On December 11, 2018, Southern Power completed the sale of a noncontrolling tax equity interest in SP Wind, which owns a portfolio of eight operating wind facilities, to three financial investors, for approximately $1.2 billion. The tax equity investors together will generally receive 40% of the cash distributions from available cash and will receive a 99% allocation of tax attributes, including PTCs. Southern Power continues to consolidate the assets and liabilities of SP Wind with the investors' shares of partnership earnings reflected in net income attributable to noncontrolling interests in the consolidated statements of income.

On November 5, 2018, Southern Power entered into an agreement with Northern States Power to sell all of its equity interests in Plant Mankato (including the 385-MW expansion currently under construction) for an aggregate purchase price of approximately $650 million. The completion of the disposition is subject to the expansion unit reaching commercial operation as well as various other customary conditions to closing, including working capital and timing adjustments. Pre-tax net income for Plant Mankato was immaterial for the years ended December 31, 2018 and 2017. This transaction is subject to FERC and state commission approvals and is expected to close mid-2019. The ultimate outcome of this matter cannot be determined at this time.

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

Southern Power has PPAs with some of Southern Company's traditional electric operating companies, other investor-owned utilities, IPPs, municipalities, and other load-serving entities, as well as commercial and industrial customers. The PPAs are expected to provide Southern Power with a stable source of revenue during their respective terms.

Many of Southern Power's PPAs have provisions that require Southern Power 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.

On January 29, 2019, Pacific Gas & Electric Company (PG&E) filed petitions to reorganize under Chapter 11 of the U.S. Bankruptcy Code. Southern Power, together with its noncontrolling partners, owns four solar facilities where PG&E is the energy off-taker for approximately 207 MWs of capacity under long-term PPAs. PG&E is also the transmission provider for these facilities and two of Southern Power's other solar facilities. Southern Power has evaluated the recoverability of its investments in these solar facilities under various scenarios, including selling the related energy into the competitive markets, and has concluded they are not impaired. At December 31, 2018, Southern Power had outstanding accounts receivables due from PG&E of $1 million related to the PPAs and $36 million related to the transmission interconnections (of which $17 million is classified in other deferred charges and assets). Southern Power does not expect a material impact to its financial statements if, as a result of the bankruptcy proceedings, PG&E does not perform in accordance with the PPAs or the terms of the PPAs are renegotiated; however, the ultimate outcome of this matter cannot be determined at this time.

Southern Power is working to maintain and expand its share of the wholesale markets. Southern Power expects there to be new demand for capacity that will develop in the 2019-2021 timeframe. The amount of available demand and timing will vary across the wholesale markets. Southern Power calculates an investment coverage ratio for its generating assets, which includes those assets owned in part with its various partners, 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) as the investment amount. With the inclusion of investments associated with the wind and natural gas facilities currently under construction, as well as other capacity and energy contracts, Southern Power has an average investment coverage ratio of 93% through 2023 and 91% through 2028, with an average remaining contract duration of approximately 14 years (including Plant Mankato, which is classified as held for sale in the financial statements). See "Acquisitions" and "Construction Projects" herein for additional information.

Natural Gas and Biomass

Southern Power'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. Southern Power typically has the ability to serve the unit or block sale customer from an alternate resource. The second type, referred to as requirements service, provides that Southern Power serve the customer's capacity and energy requirements from a combination of the customer's own generating units and from Southern Power resources not dedicated to serve unit or block sales. Southern Power has rights to purchase power provided by the requirements customers' resources when economically viable.

As a general matter, substantially all of the PPAs provide that the purchasers are responsible for either procuring the fuel (tolling agreements) or reimbursing Southern Power 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, Southern Power may be responsible for excess fuel costs. With respect to fuel transportation risk, most of Southern Power'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 Southern Power's exposure to certain operation and maintenance costs, Southern Power has LTSAs. See Note 1 to the financial statements under "Long-Term Service Agreements" for additional information.

Solar and Wind

Southern Power'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 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. Generally, under the solar and wind generation PPAs, the purchasing party retains the right to keep or resell the renewable energy credits.

Environmental Matters

Southern Power'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. Southern Power 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, fuel prices, and the outcome of pending and/or future legal challenges.

New or revised environmental laws and regulations could affect many areas of Southern Power's operations. Southern Power'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 Southern Power'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 Southern Power 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) to address impacts of SO_2 and NO_X emissions from fossil fuel-fired electric generating plants. CSAPR establishes emissions trading programs and budgets for certain states and allocates emissions allowances for sources in those states. In 2016, the EPA published a final rule establishing more stringent ozone season NO_X emissions budgets in Alabama and Texas. The EPA also removed North Carolina from this particular CSAPR program. Georgia's ozone season NO_X emissions budget remained unchanged. Increases in either future fossil fuel-fired generation or the availability or cost of CSAPR allowances could have a negative financial impact on results of operations for Southern Power.

Water Quality

In 2014, the EPA finalized requirements under Section 316(b) of the Clean Water Act (CWA) to regulate cooling water intake structures (CWIS) to minimize their effects on fish and other aquatic life at existing power plants (e.g. coal, natural gas, oil, and nuclear generating plants) and manufacturing facilities. The regulation requires plant-specific studies to determine applicable CWIS changes to protect organisms that either get caught on the intake screens (impingement) or are drawn into the cooling system (entrainment). Southern Power is conducting these studies and currently anticipates such changes will be limited to minor additions of monitoring equipment at certain of its electric generating plants. However, the ultimate impact of this rule will depend on the outcome of these plant-specific studies, any additional protective measures required to be incorporated into each plant's National Pollutant Discharge Elimination System (NPDES) permit based on site-specific factors, and the outcome of any legal challenges.

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, canals, and wastewater treatment ponds), which could impact new generation projects. The EPA and the Corps are expected to publish a final rule in 2019 to replace the 2015 WOTUS definition. The impact of any changes to the 2015 WOTUS rule will depend on the content of this final rule and the outcome of any legal challenges.

Global Climate Issues

On December 20, 2018, the EPA published a proposed review of the Standards of Performance for Greenhouse Gas Emissions from New, Modified, and Reconstructed Stationary Sources: Electric Utility Generating Units final rule (2015 NSPS rule). The EPA's final 2015 NSPS rule set standards of performance for new, modified, and reconstructed electric utility generating units which included stationary combustion turbines and fossil-fired steam boilers. This proposal reduces the stringency of the 2015 NSPS rule by not basing the new and reconstructed fossil-fired steam boiler standards on partial carbon capture and sequestration. The impact of any changes to this rule will depend on the content of the final rule and the outcome of any legal challenges.

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, Southern Power's 2017 GHG emissions were approximately 13 million metric tons of CO_2 equivalent. The preliminary estimate of Southern Power's 2018 GHG emissions on the same basis is approximately 14 million metric tons of CO_2 equivalent.

Income Tax Matters

Consolidated Income Taxes

On behalf of Southern Power, 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. 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 Southern Power's ability to utilize certain tax credits. See "Tax Credits" and ACCOUNTING POLICIES – "Application of Critical Accounting Policies and Estimates" herein and Note 10 to the financial statements for additional information.

Southern Power currently has unutilized federal ITC and PTC carryforwards totaling approximately $2.1 billion, and thus has utilized tax equity partnerships where the tax partner will take significantly all of the respective federal tax benefits on a prospective basis. These tax equity partnerships are consolidated in Southern Power's financial statements using the HLBV methodology to allocate partnership gains and losses. See Note 1 to the financial statements for additional information.

Federal Tax Reform Legislation

In December 2017, the Tax Reform Legislation was signed into law and became effective on January 1, 2018. The Tax Reform Legislation, among other things, reduced the federal corporate income tax rate to 21%, retained existing renewable energy incentives, and repealed the corporate alternative minimum tax. 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.

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 provided 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 Power considered all amounts recorded in the financial statements as a result of the Tax Reform Legislation "provisional" as discussed in SAB 118 and subject to revision prior to filing its 2017 tax return in the fourth quarter 2018. Southern Power recognized tax benefits of $743 million in 2017. Following the filing of its 2017 tax return, Southern Power recorded tax expense of $79 million to adjust the provisional amount for a total net tax benefit of $664 million as a result of the Tax Reform Legislation. As of December 31, 2018, Southern Power considered the measurement of impacts from the Tax Reform Legislation on deferred income tax assets and liabilities, primarily due to the impact of the reduction of the corporate income tax rate, to be complete.

However, the IRS continues to issue regulations that provide further interpretation and guidance on the law and each state's adoption of the provisions contained in the Tax Reform Legislation remains uncertain. The ultimate impact of this matter cannot be determined at this time. In addition, the regulatory treatment of certain impacts of the Tax Reform Legislation is subject to the discretion of the FERC. See Note 10 to the financial statements under "Current and Deferred Income Taxes" for additional information.

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. Southern Power 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 may continue to have, a material impact on Southern Power's cash flows and net income. In 2018, Southern Power sold noncontrolling tax equity interests in SP Wind and Cactus Flats, which both qualify for PTCs, and Gaskell West 1, which qualifies for ITCs. Under these partnerships, the tax equity investors will receive 99% of the PTC and ITC tax benefits and, therefore, Southern Power's tax benefits will be materially reduced. At December 31, 2018,

Southern Power had approximately $2.1 billion of unutilized ITCs and PTCs, which are currently expected to be fully utilized by 2022, but could be further delayed. See Note 1 to the financial statements under "Income and Other Taxes" and Note 10 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 associated 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. Southern Power is not expecting material cash flows from bonus depreciation for the 2018 or 2019 tax years. However, any cash flows resulting from bonus depreciation would also be impacted by Southern Power's use of tax equity partnerships. See Note 10 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.

Acquisitions

During 2018, Southern Power acquired and completed the project below and acquired the Wild Horse Mountain and Reading wind facilities discussed under "Construction Projects" herein. See Note 15 to the financial statements under "Southern Power" for additional information.

Project Facility	Resource	Seller, Acquisition Date	Approximate Nameplate Capacity (*MW*)	Location	Ownership Percentage	Actual COD	PPA Counterparties	PPA Contract Period
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

(*) Southern Power owns 100% of the class B membership interests under a tax equity partnership.

The Gaskell West 1 facility did not have operating revenues or activities prior to being placed in service during March 2018.

Construction Projects

Construction Projects Completed and/or in Progress

During 2018, in accordance with its growth strategy, Southern Power started, continued, or completed 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, 2018							
Cactus Flats [a]	Wind	148	Concho County, TX	100% of Class B	July 2018	General Motors, LLC and General Mills Operations, LLC	12 years and 15 years
Projects Under Construction at December 31, 2018							
Mankato expansion [b]	Natural Gas	385	Mankato, MN	100%	Second quarter 2019	Northern States Power Company	20 years
Wild Horse Mountain [c]	Wind	100	Pushmataha County, OK	100%	Fourth quarter 2019	Arkansas Electric Cooperative	20 years
Reading [d]	Wind	200	Osage and Lyon Counties, KS	100%	Second quarter 2020	Royal Caribbean Cruises LTD	12 years

(a) In July 2017, Southern Power purchased 100% of the Cactus Flats facility. In August 2018, Southern Power closed on a tax equity partnership and now owns 100% of the class B membership interests.

(b) In November 2018, Southern Power entered into an agreement to sell all of its equity interests in Plant Mankato, including this expansion currently under construction. See "Sales of Natural Gas Plants" below.

(c) In May 2018, Southern Power purchased 100% of the Wild Horse Mountain facility. Southern Power may enter into a tax equity partnership, in which case it would then own 100% of the class B membership interests. The ultimate outcome of this matter cannot be determined at this time.

(d) In August 2018, Southern Power purchased 100% of the membership interests of the Reading facility from the joint development arrangement with Renewable Energy Systems Americas, Inc. described below. Southern Power may enter into a tax equity partnership, in which case it would then own 100% of the class B membership interests. The ultimate outcome of this matter cannot be determined at this time.

Total aggregate construction costs for projects under construction at December 31, 2018, excluding acquisition costs, are expected to be between $575 million and $640 million for the Plant Mankato expansion, Wild Horse Mountain, and Reading facilities. At December 31, 2018, total costs of construction incurred for these projects was $289 million, and is included in CWIP, except for the Plant Mankato expansion, which is included in assets held for sale in the financial statements. See Note 15 to the financial statements under "Southern Power" and "Assets Held for Sale" for additional information.

Development Projects

During 2017, Southern Power purchased wind turbine equipment to be used for various development and construction projects. Any wind projects using this equipment and reaching commercial operation by the end of 2021 are expected to qualify for 80% PTCs.

During 2016, Southern Power entered into a joint development agreement with Renewable Energy Systems Americas, Inc. (RES) to develop and construct wind projects. Concurrent with the agreement, Southern Power purchased wind turbine equipment from Siemens Wind Power, Inc. and Vestas-American Wind Technology, Inc. to be used for construction of these projects. Several wind projects using this equipment, as well as other purchased equipment, have successfully originated, directly or indirectly, from the partnership with RES and are expected to reach commercial operation before the end of 2020, thus qualifying for 100% PTCs.

Southern Power continues to evaluate and refine the deployment of the wind turbine equipment to potential joint development and construction projects as well as the amount of MW capacity to be constructed. During the third quarter 2018, as a result of a review of various options for probable dispositions of wind turbine equipment not deployed to development or construction projects, Southern Power recorded a $36 million asset impairment charge on the equipment.

Subsequent to December 31, 2018 and as part of management's continuous review of disposition options, approximately $53 million of this equipment is being marketed for sale and will be classified as held for sale.

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

Sales of Renewable Facility Interests

On May 22, 2018, Southern Power completed the sale of a noncontrolling 33% equity interest in SP Solar, a limited partnership indirectly owning substantially all of Southern Power's solar facilities, to Global Atlantic for approximately $1.2 billion. Since Southern Power retains control of the limited partnership through its wholly-owned general partner, the sale was recorded as an equity transaction and Southern Power will continue to consolidate SP Solar in its financial statements. On the date of the transaction, the noncontrolling interest was increased by $511 million to reflect 33% of the carrying value of the partnership. This difference, partially offset by the tax impact and other related transaction charges, also resulted in a $410 million decrease to Southern Power's common stockholder's equity.

On December 11, 2018, Southern Power completed the sale of a noncontrolling tax equity interest in SP Wind, which owns a portfolio of eight operating wind facilities, to three financial investors for approximately $1.2 billion. The tax equity investors together will generally receive 40% of the cash distributions from available cash and will receive 99% of the tax attributes, including future production tax credits. Since Southern Power retains control of SP Wind, Southern Power will continue to consolidate SP Wind in its financial statements.

Sales of Natural Gas Plants

On December 4, 2018, Southern Power completed the sale of all of its equity interests in the Florida Plants to NextEra Energy for $203 million. In contemplation of this sale transaction, Southern Power recorded an asset impairment charge of approximately $119 million ($89 million after tax) in May 2018. Pre-tax net income for the Florida Plants was $49 million and $37 million for the period from January 1, 2018 to December 4, 2018 and for the year ended December 31, 2017, respectively.

On November 5, 2018, Southern Power entered into an agreement with Northern States Power to sell all of its equity interests in Plant Mankato (including the 385-MW expansion currently under construction) for an aggregate purchase price of approximately $650 million. The completion of the disposition is subject to the expansion unit reaching commercial operation as well as various other customary conditions to closing, including working capital and timing adjustments. The ultimate purchase price will decrease $66,667 per day for each day after June 1, 2019 that the expansion has not achieved commercial operation, not to exceed $15 million. Pre-tax net income for Plant Mankato was immaterial for the years ended December 31, 2018 and 2017. This

transaction is subject to FERC and state commission approvals and is expected to close mid-2019. The assets and liabilities of Plant Mankato are classified as held for sale as of December 31, 2018.

See Note 15 to the financial statements under "Southern Power" and "Assets Held for Sale" for additional information. The ultimate outcome of this matter cannot be determined at this time.

Other Matters

Southern Power is involved in various other matters being litigated and regulatory matters that could affect future earnings. In addition, Southern Power is subject to certain claims and legal actions arising in the ordinary course of business. Southern Power's business activities are subject to extensive governmental regulation related to public health and the environment, such as laws and regulations governing air, water, land, and protection of other natural resources. Litigation over environmental issues and claims of various types, including property damage, personal injury, common law nuisance, and citizen enforcement of environmental laws and regulations, 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 in Note 3 to the financial statements herein, management does not anticipate that the ultimate liabilities, if any, arising from such current proceedings would have a material effect on Southern Power's financial statements.

Southern Power indirectly owns a 51% membership interest in RE Roserock LLC (Roserock), the owner of the Roserock facility in Pecos County, Texas. Prior to the facility being placed in service in 2016, certain solar panels were damaged during installation by the construction contractor, McCarthy Building Companies, Inc. (McCarthy), and certain solar panels were damaged by a hail event that also occurred during construction. In connection therewith, Southern Power is withholding payments of approximately $26 million from the construction contractor, which has placed a lien on the Roserock facility for the same amount. In May 2017, Roserock filed a lawsuit in the state district court in Pecos County, Texas, (State Court lawsuit) 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 the hail storm and McCarthy's installation practices. On June 1, 2018, the court in the State Court lawsuit granted Roserock's motion for partial summary judgment, finding that the insurers were in breach of contract and in violation of the Texas Insurance Code for failing to pay any monies owed for the hail claim. In addition to the State Court lawsuit, lawsuits were filed between Roserock and McCarthy, as well as other parties, and that litigation has been consolidated in the U.S. District Court for the Western District of Texas. Southern Power 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

Southern Power prepares its consolidated financial statements in accordance with GAAP. Significant accounting policies are described in Notes 1, 4, and 10 to the financial statements. In the application of these policies, certain estimates are made that may have a material impact on Southern Power'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

Southern Power's revenue recognition depends on appropriate classification and documentation of transactions in accordance with GAAP. In general, Southern Power'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 14 to the financial statements. Southern Power'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

Southern Power 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, Southern Power performs further analysis as to whether the lease is classified as operating, financing, or sales-type. All of Southern Power'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 Southern Power'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, Southern Power 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).

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 Southern Power's available generating capacity) are accounted for as executory contracts. For contracts that have a capacity charge, the revenue is generally recognized in the period that it becomes billable. Revenues related to energy and ancillary services are recognized in the period the energy is delivered or the service is rendered. See Note 4 to the financial statements for additional information.

Cash Flow Hedge Transactions

Southern Power 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.

Derivative (Non-Hedge) 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

Southern Power's investments in long-lived assets are primarily generation assets, whether in service or under construction. Southern Power's intangible assets arise from certain acquisitions and consist of acquired PPAs, which are amortized to revenue over the term of the respective PPAs. Southern Power 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, the inability to remarket generating capacity for an extended period, the unplanned termination of a customer contract or inability of a customer to perform under the terms of the contract, or the inability to deploy wind turbine equipment to a development project. 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.

In addition, when assets are identified as held for sale, an impairment loss is recognized to the extent that the carrying value of the assets or asset group exceeds the asset fair value less cost to sell. In 2018, an impairment charge of $119 million was recorded for the Florida Plants concurrent with the assets being identified as held for sale as a result of a signed purchase and sale agreement. Also in 2018, an impairment charge of $36 million was recorded for wind turbine equipment that is no longer likely to be deployed to a wind generation project.

Acquisition Accounting

Southern Power may acquire generation assets as part of its overall growth strategy. At the time of an acquisition, Southern Power will assess if these assets and activities meet the definition of a business. For acquisitions that meet the definition of a business, Southern Power 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 Southern Power 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 Southern Power 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, Southern Power fair values the arrangement with any changes recorded in the consolidated statements of income. See Note 13 to the financial statements for additional fair value information and Note 15 to the financial statements for additional information on recent acquisitions.

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 Southern Power operates.

On behalf of Southern Power, 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 Southern Power's, as well as Southern Company's, current financial position and results 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 Power's financial statements.

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

Recently Issued Accounting Standards

See Note 1 to the financial statements under "Recently Adopted Accounting Standards" for additional information.

In 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 Southern Power adopted the new standard effective January 1, 2019.

Southern Power elected the transition methodology provided by ASU No. 2018-11, *Leases (Topic 842): Targeted Improvements*, whereby the requirements of ASU 2016-02 are applied on a prospective basis as of the adoption date of January 1, 2019, without restating prior periods. Southern Power elected the package of practical expedients provided by ASU 2016-02 that allows prior determinations of whether existing contracts are, or contain, leases and the classification of existing leases to continue without reassessment. Additionally, Southern Power expects to apply the use-of-hindsight practical expedient in determining lease terms as of the date of adoption. Southern Power also made accounting policy elections to account for short-term leases in all asset classes as off-balance sheet leases and combined lessee lease and non-lease components in the computations of lease obligations and right-of-use assets for most asset classes, while lessor lease and non-lease components are accounted for separately.

Southern Power completed the implementation of a new application to track and account for its leases and updated its internal controls and accounting policies to support the accounting for leases under ASU 2016-02. Southern Power completed its lease inventory and determined its most significant leases as a lessee involve real estate. In the first quarter 2019, the adoption of ASU 2016-02 resulted in recording lease liabilities and right-of-use assets on Southern Power's balance sheet each totaling approximately $0.4 billion, with no impact on Southern Power's statement of income.

FINANCIAL CONDITION AND LIQUIDITY

Overview

Southern Power's financial condition remained stable at December 31, 2018. Southern Power'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 Southern Power'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 Southern Power's cash needs. For the three-year period from 2019 through 2021, Southern Power's projected common stock dividends, distributions to noncontrolling interests, capital expenditures, and debt maturities are expected to exceed operating cash flows. Southern Power plans to finance future cash needs in excess of its operating cash flows primarily through external securities issuances, borrowings from financial institutions, and equity contributions from Southern Company. Southern Power intends to continue to monitor its access to short-term and long-term capital markets as well as its bank credit agreements to meet future capital and liquidity needs. See "Sources of Capital," "Financing Activities," and "Contractual Obligations" herein for additional information on lines of credit.

Southern Power also utilizes tax equity partnerships, as one of its financing sources, where the tax partner takes significantly all of the federal tax benefits. These tax equity partnerships are consolidated in Southern Power's financial statements and are accounted for using a HLBV methodology to allocate partnership gains and losses. During 2018, Southern Power obtained tax equity funding for the Gaskell West 1 solar project, the Cactus Flats wind project, and the SP Wind portfolio and received proceeds of approximately $26 million, $122 million, and $1.2 billion, respectively.

On May 22, 2018, Southern Power completed the sale of a noncontrolling 33% equity interest in SP Solar, a limited partnership indirectly owning substantially all of Southern Power's solar facilities, to Global Atlantic for approximately $1.2 billion. Accordingly, Global Atlantic will receive 33% of all cash distributions paid by SP Solar.

On December 4, 2018, Southern Power completed the sale of all of its equity interests in the Florida Plants to NextEra Energy for $203 million. On November 5, 2018, Southern Power entered into an agreement with Northern States Power to sell all of its equity interests in Plant Mankato (including the 385-MW expansion currently under construction) for an aggregate purchase price of approximately $650 million. The completion of the disposition is subject to the expansion unit reaching commercial operation as well as various other customary conditions to closing, and is expected to close mid-2019. The ultimate outcome of this matter cannot be determined at this time.

Net cash provided from operating activities totaled $631 million in 2018, a decrease of $524 million compared to 2017. The decrease was primarily due to lower income tax refunds as a result of taxable gains arising from the sales of noncontrolling interests in SP Solar and SP Wind, as well as the sale of the Florida Plants. At December 31, 2018, Southern Power had $2.1 billion of unutilized ITCs and PTCs which are expected to be fully utilized by 2022. See FUTURE EARNINGS POTENTIAL – "Income Tax Matters – Tax Credits" herein for additional information. Net cash provided from operating activities totaled $1.2 billion in 2017, an increase of $816 million compared to 2016 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.

Net cash used for investing activities totaled $227 million, $1.6 billion, and $4.8 billion in 2018, 2017, and 2016, respectively, and decreased in 2018 primarily due to fewer acquisitions and completion of construction of renewable facilities during 2017 and 2018. See FUTURE EARNINGS POTENTIAL – "Acquisitions" and "Construction Projects" herein and Note 15 to the financial statements for additional information.

Net cash used for financing activities totaled $363 million in 2018 primarily due to returns of capital to Southern Company, payments of common stock dividends, and distributions to noncontrolling interests, partially offset by capital contributions from noncontrolling interests. 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.

Significant balance sheet changes include a $745 million decrease in plant in service and a $576 million increase in assets held for sale primarily due to completed and planned plant divestitures and a $355 million increase in deferred income taxes primarily due to $551 million related to the sales of noncontrolling interests in SP Solar and SP Wind and $129 million in additional unutilized PTCs, partially offset by a $333 million decrease in the federal NOL carryforward.

Sources of Capital

Southern Power 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, divestitures, 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. With respect to the public offering of securities, Southern Power (excluding its subsidiaries) issues and offers debt registered on registration statements filed with the SEC under the Securities Act of 1933, as amended.

Southern Power's current liabilities sometimes exceed current assets due to the use of short-term debt as a funding source and construction payables, as well as fluctuations in cash needs due to seasonality. Southern Power 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, equity contributions from Southern Company, external securities issuances, and operating cash flows.

Southern Power obtains its own financing separately without any credit support from Southern Company or any other affiliate. The Southern Company system does not maintain a centralized cash or money pool. Therefore, funds of Southern Power are not commingled with funds of any other company in the Southern Company system. To meet liquidity and capital resource requirements, Southern Power had cash and cash equivalents of approximately $181 million at December 31, 2018.

Southern Power'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. Southern Power's subsidiaries are not issuers under the commercial paper program. Short-term borrowings are included in notes payable on the consolidated balance sheets.

Details of short-term borrowings were as follows:

	Short-term Borrowings at the End of the Period		Short-term Borrowings 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, 2018					
Commercial paper	**$ —**	**—%**	**$ 77**	**2.2%**	**$ 304**
Short-term bank debt	**100**	**3.1%**	**111**	**2.7%**	**200**
Total	**$ 100**	**3.1%**	**$ 188**	**2.5%**	
December 31, 2017					
Commercial paper	$ 105	2.0%	$ 215	1.4%	$ 419
Short-term bank debt	—	—%	17	2.1%	209
Total	$ 105	2.0%	$ 232	1.4%	
December 31, 2016					
Commercial paper	$ —	—%	$ 56	0.8%	$ 310
Total	$ —	—%	$ 56	0.8%	

(*) Average and maximum amounts are based upon daily balances during the twelve-month periods ended December 31, 2018, 2017, and 2016.

In addition to the short-term borrowings of Southern Power included in the table above, at December 31, 2016, Southern Power subsidiaries assumed credit agreements (Project Credit Facilities) with the acquisition of certain solar facilities, which were non-recourse to the Southern Power parent 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.

Company Credit Facilities

At December 31, 2018, Southern Power had a committed credit facility (Facility) of $750 million expiring in 2022, of which $23 million has been used for letters of credit and $727 million remains unused. Southern Power'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 Southern Power's commercial paper program. A portion of the unused credit under the Facility is allocated to provide liquidity support for Southern Power's commercial paper program. Subject to applicable market conditions, Southern Power expects to renew or replace the Facility, as needed, prior to expiration. In connection therewith, Southern Power may extend the maturity date and/or increase or decrease the lending commitment thereunder. See Note 8 to the financial statements under "Bank Credit Arrangements" for additional information.

The Facility, as well as Southern Power'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 Southern Power. For the purposes of this definition, debt would exclude any project debt incurred by certain subsidiaries of Southern Power to the extent such debt is non-recourse to Southern Power, and capitalization would exclude the capital stock or other equity attributable to such subsidiary. Southern Power is currently in compliance with all of these covenants.

Southern Power also has a $120 million continuing letter of credit facility for standby letters of credit. In December 2018, Southern Power amended the letter of credit facility, which, among other things, extended the expiration date from 2019 to 2021. At December 31, 2018, $103 million has been used for letters of credit, primarily as credit support for PPA requirements, and $17 million was unused. Southern Power's subsidiaries are not parties to this letter of credit facility.

In addition, at December 31, 2018 and 2017, Southern Power had $103 million and $113 million, respectively, of cash collateral posted related to PPA requirements.

Financing Activities

Senior Notes

In June 2018, Southern Power repaid $350 million aggregate principal amount of Series 2015A 1.50% Senior Notes due June 1, 2018.

In addition to any financings that may be necessary to meet capital requirements and contractual obligations, Southern Power 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 May 2018, Southern Power repaid $420 million aggregate principal amount of long-term floating rate bank loans.

Also in May 2018, Southern Power entered into two short-term floating rate bank loans, each for an aggregate principal amount of $100 million, which bear interest based on one-month LIBOR, and proceeds being used for general corporate purposes. In November 2018, Southern Power repaid one of these short-term loans.

Credit Rating Risk

Southern Power 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, 2018 were as follows:

Credit Ratings	Maximum Potential Collateral Requirements
	(in millions)
At BBB and/or Baa2	$ 29
At BBB- and/or Baa3	$ 338
At BB+ and/or Ba1 (*)	$ 980

(*) 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 either Alabama Power or Georgia Power (affiliate companies of Southern 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 Southern Power to access capital markets and would be likely to impact the cost at which it does so.

In addition, Southern Power has a PPA that could require collateral, but not accelerated payment, in the event of a downgrade of Southern Power'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 September 28, 2018, Fitch assigned a negative rating outlook to the ratings of Southern Company and certain of its subsidiaries (including Southern Power).

Market Price Risk

Southern Power 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, Southern Power nets its exposures, where possible, to take advantage of natural offsets and enters into various derivative transactions for the remaining exposures pursuant to Southern Power's policies in areas such as counterparty exposure and risk management practices. Southern Power'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, 2018, Southern Power had $525 million of long-term variable rate notes outstanding. If Southern Power sustained a 100 basis point change in interest rates for its variable interest rate exposure, the change would affect annualized interest expense by approximately $5 million at December 31, 2018. Since a significant portion of outstanding indebtedness bears interest at fixed rates, Southern Power 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.

Southern Power had foreign currency denominated debt of €1.1 billion at December 31, 2018. Southern Power 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 Southern Power'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, Southern Power's exposure to market volatility in commodity fuel prices and prices of electricity is generally limited. 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.

For the years ended December 31, 2018 and 2017, the changes in fair value of energy-related derivative contracts associated with both power and natural gas positions were as follows:

		2018		2017
		(in millions)		
Contracts outstanding at the beginning of period, assets (liabilities), net	**$**	**(10)**	$	16
Contracts realized or settled		**10**		(17)
Current period changes (*)		**(4)**		(9)
Contracts outstanding at the end of period, assets (liabilities), net	**$**	**(4)**	$	(10)

(*) 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, 2018 and 2017, the changes in contracts outstanding were attributable to both the volume and the prices of power and natural gas as follows:

		2018		2017
Power – net sold				
MWH (in millions)		**2.5**		3.0
Weighted average contract cost per MWH above (below) market prices (in dollars)	**$**	**(0.23)**	$	(2.67)
Natural Gas – net purchased				
Commodity - mmBtu (in millions)		**15.0**		14.4
Commodity - weighted average contract cost per mmBtu above (below) market prices (in dollars)	**$**	**0.22**	$	0.12

Gains and losses on energy-related derivatives designated as cash flow hedges which are used by Southern Power 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.

Southern Power 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 13 to the financial statements for further discussion of fair value measurements. The energy-related derivative contracts outstanding at December 31, 2018 mature through 2020.

Southern Power is exposed to losses related to financial instruments in the event of counterparties' nonperformance. Southern Power 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. Southern Power has also established risk management policies and controls to determine and monitor the creditworthiness of counterparties in order to mitigate Southern Power's exposure to counterparty credit risk. Therefore, Southern Power 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 14 to the financial statements for additional information.

Capital Requirements and Contractual Obligations

The capital program of Southern Power is subject to periodic review and revision and is currently estimated to total $0.9 billion over the next five years through 2023. This includes committed construction, capital improvements, and work to be performed

under LTSAs, totaling approximately $300 million for each of 2019 and 2020 and an average of approximately $100 million each year from 2021 through 2023. In addition, Southern Power has a further $2.3 billion in planned expenditures for plant acquisitions and placeholder growth, or approximately $0.5 billion per year on average for 2019 through 2023. Planned expenditures for plant acquisitions and placeholder growth may vary materially due to market opportunities and Southern Power'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 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 15 to the financial statements under "Southern Power" for additional information.

Southern Power forecasts contributions to the pension and other postretirement benefit plans over a three-year period. Southern Power anticipates no mandatory contributions to the qualified pension plan during the next three years. See Note 11 to the financial statements for additional information.

Funding requirements related to obligations associated with scheduled maturities of long-term debt, as well as the related interest, leases, derivative obligations, and other purchase commitments are detailed in the contractual obligations table that follows. See Notes 1, 8, 9, and 14 to the financial statements for additional information.

Contractual Obligations

Contractual obligations at December 31, 2018 were as follows:

	2019	2020-2021	2022-2023	After 2023	Total
			(in millions)		
Long-term debt[a] —					
Principal	$ 600	$ 1,125	$ 967	$ 2,339	$ 5,031
Interest	179	310	250	1,409	2,148
Financial derivative obligations[b]	6	2	—	—	8
Operating leases[c]	23	48	50	874	995
Purchase commitments —					
Capital[d]	252	461	144	—	857
Fuel[e]	601	744	369	32	1,746
Purchased power[f]	41	83	—	—	124
Other[g]	168	309	221	1,471	2,169
Total	$ 1,870	$ 3,082	$ 2,001	$ 6,125	$ 13,078

(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 an $18 million gain related to the foreign currency hedge of €1.1 billion. Southern Power 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 14 to the financial statements.

(c) Operating lease commitments include certain land leases for solar and wind facilities that may be subject to annual price escalation based on indices. See Note 9 to the financial statements for additional information.

(d) Southern Power provides estimated capital expenditures for a five-year period, including capital expenditures associated with environmental regulations. Excluded from these amounts are planned expenditures for plant acquisitions and placeholder growth of $2.3 billion. Also excluded from these amounts are capital expenditures covered under LTSAs which are reflected in "Other." See Note (g) below. At December 31, 2018, significant purchase commitments were outstanding in connection with the construction program. No ARO settlements are projected during the five-year period.

(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 NYMEX future prices at December 31, 2018.

(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.

MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS
Southern Company Gas and Subsidiary Companies 2018 Annual Report

OVERVIEW

Business Activities

Southern Company Gas is an energy services holding company whose primary business is the distribution of natural gas. Subsequent to the dispositions of Elizabethtown Gas, Elkton Gas, and Florida City Gas discussed herein under "Merger, Acquisition, and Disposition Activities," Southern Company Gas has natural gas distribution utilities in four states – Illinois, Georgia, Virginia, and Tennessee. Southern Company Gas is also involved in several other complementary businesses.

Southern Company Gas manages its business through four reportable segments – gas distribution operations, gas pipeline investments, wholesale gas services, which includes Sequent, a natural gas asset optimization company, and gas marketing services, which includes SouthStar, a provider of energy-related products and services to natural gas markets – and one non-reportable segment, all other. During the fourth quarter 2018, Southern Company Gas changed its reportable segments to further align with the way its new Chief Operating Decision Maker reviews operating results and has reclassified prior years' data to conform to the new reportable segment presentation. This change resulted in a new reportable segment, gas pipeline investments, which was formerly included in gas midstream operations. Gas pipeline investments consists primarily of joint ventures in natural gas pipeline investments including a 50% interest in SNG, two significant pipeline construction projects, and a 50% joint ownership interest in the Dalton Pipeline. Gas distribution operations, wholesale gas services, and gas marketing services continue to remain as separate reportable segments and reflect the impact of the Southern Company Gas Dispositions. The all other non-reportable segment includes segments below the quantitative threshold for separate disclosure, including the storage and fuels operations that were formerly included in gas midstream operations, and other subsidiaries that fall below the quantitative threshold for separate disclosure. See Notes 5, 7, and 16 to the financial statements for additional information.

Many factors affect the opportunities, challenges, and risks of Southern Company Gas' 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, safety, reliability, resilience, natural gas, and capital expenditures, including updating and expanding the natural gas distribution systems. The natural gas distribution utilities have various regulatory mechanisms that 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 Southern Company Gas for the foreseeable future. Nicor Gas filed a rate case on November 9, 2018 and Atlanta Gas Light is required to file a rate case no later than June 1, 2019. These rate cases are both expected to conclude in 2019; however, the ultimate outcome of these matters cannot be determined at this time. See FUTURE EARNINGS POTENTIAL – "Regulatory Matters – Rate Proceedings" herein and Note 2 to the financial statements under "Southern Company Gas – Rate Proceedings" for additional information.

Merger, Acquisition, and Disposition Activities

In 2016, Southern Company Gas completed the Merger, pursuant to which Southern Company Gas 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 Southern Company Gas' 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 15 to the financial statements under "Southern Company Merger with Southern Company Gas" for additional information.

In 2016, Southern Company Gas completed its purchase of Piedmont's 15% interest in SouthStar for $160 million and paid $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. In March 2017, Southern Company Gas made an additional $50 million contribution to maintain its 50% equity interest in SNG. See Note 7 to the financial statements under "Southern Company Gas" and Note 15 to the financial statements under "Southern Company Gas – Investment in SNG" for additional information.

During 2018, Southern Company Gas completed the following sales, resulting in approximately $2.7 billion in aggregate proceeds:

- On June 4, 2018, Southern Company Gas completed the stock sale of Pivotal Home Solutions to American Water Enterprises LLC for a total cash purchase price of $365 million, which includes the final working capital adjustment.

This disposition resulted in a net loss of $67 million, which includes $34 million of income tax expense. In contemplation of the transaction, a goodwill impairment charge of $42 million was recorded in 2018.

- On July 1, 2018, a Southern Company Gas subsidiary, Pivotal Utility Holdings, completed the sales 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, which includes the final working capital and other adjustments. This disposition resulted in a pre-tax gain that was entirely offset by $205 million of income tax expense, resulting in no material net income impact.
- On July 29, 2018, Southern Company Gas and its wholly-owned direct subsidiary, NUI Corporation, completed the stock sale of Pivotal Utility Holdings, which primarily consisted of Florida City Gas, to NextEra Energy for a total cash purchase price of $587 million, which includes the final working capital adjustment less indebtedness assumed at closing. This disposition resulted in a net gain of $16 million, which includes $103 million of income tax expense.

The after-tax gain and loss on these dispositions included income tax expense on goodwill not deductible for tax purposes and for which a deferred tax liability had not been recorded previously. See Note 15 to the financial statements under "Southern Company Gas" herein for additional information.

Operating Metrics

Southern Company Gas continues to focus on several operating metrics, including Heating Degree Days, customer count, and volumes of natural gas sold.

Southern Company Gas 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 Southern Company Gas' distribution system. With the exception of Nicor Gas, Southern Company Gas 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 operating revenues from utility customers in Illinois and gas marketing services customers primarily in Georgia and Illinois can be impacted by warmer- or colder-than-normal weather. Southern Company Gas utilizes weather hedges to limit the negative income impacts in the event of warmer-than-normal weather, while retaining a significant portion of the positive benefits of colder-than-normal weather 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 and Illinois.

Southern Company Gas' 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. Southern Company Gas' 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 Southern Company Gas' annual results. Thus, Southern Company Gas' 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	Net Income
Successor - 2018	68.7%	96.0%
Successor - 2017	67.3%	73.7%
Successor - July 1, 2016 through December 31, 2016	67.1%	96.5%
Predecessor - January 1, 2016 through June 30, 2016	70.0%	138.9%

Earnings

Net income attributable to Southern Company Gas for the successor year ended December 31, 2018 was $372 million, representing a $129 million, or 53.1%, increase over the previous year. Excluding a $121 million decrease related to the Southern Company Gas Dispositions, net income attributable to Southern Company Gas increased $251 million. This increase was primarily due to lower income tax expense, increased commercial activity at wholesale gas services, increased operating revenues from infrastructure replacement programs and base rate changes at gas distribution operations, and higher earnings from Southern Company Gas' investment in SNG. These increases were partially offset by higher other operations and maintenance expenses primarily due to increased compensation and benefit costs and disposition-related costs, higher depreciation on continued infrastructure investments at gas distribution operations, additional interest expense on new debt issuances, and an increase in charitable donations.

Net income attributable to Southern Company Gas for the successor year ended December 31, 2017 was $243 million, which included net income of $53 million from Southern Company Gas' investment in SNG and $44 million generated from Southern Company Gas' 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 Southern Company Gas' 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 10 and 15 to the financial statements for additional information.

Net income attributable to Southern Company Gas 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 Southern Company Gas for the predecessor period of January 1, 2016 through June 30, 2016 was $131 million, which included $41 million of Merger-related expenses and $14 million of net income attributable to the SouthStar noncontrolling interest, which Southern Company Gas purchased in October 2016. Net income for the predecessor period 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 Southern Company Gas follows:

	Successor			Predecessor
	Year Ended December 31, 2018	Year Ended December 31, 2017	July 1, 2016 through December 31, 2016	January 1, 2016 through June 30, 2016
		(in millions)		*(in millions)*
Operating revenues	**$ 3,909**	$ 3,920	$ 1,652	$ 1,905
Cost of natural gas	**1,539**	1,601	613	755
Cost of other sales	**12**	29	10	14
Other operations and maintenance	**981**	945	480	452
Depreciation and amortization	**500**	501	238	206
Taxes other than income taxes	**211**	184	71	99
Goodwill impairment	**42**	—	—	—
Gain on dispositions, net	**(291)**	—	—	—
Merger-related expenses	**—**	—	41	56
Total operating expenses	**2,994**	3,260	1,453	1,582
Operating income	**915**	660	199	323
Earnings from equity method investments	**148**	106	60	2
Interest expense, net of amounts capitalized	**228**	200	81	96
Other income (expense), net	**1**	44	12	3
Earnings before income taxes	**836**	610	190	232
Income taxes	**464**	367	76	87
Net Income	**372**	243	114	145
Net income attributable to noncontrolling interest(*)	**—**	—	—	14
Net Income Attributable to Southern Company Gas	**$ 372**	$ 243	$ 114	$ 131

(*) Includes Piedmont's 15% interest in SouthStar, which was acquired by Southern Company Gas in 2016. See Note 7 to the financial statements under "Southern Company Gas" for additional information.

The Southern Company Gas Dispositions were completed by July 29, 2018 and represent the primary variance driver for the 2018 changes. Detailed variance explanations are provided herein. See Note 15 to the financial statements under "Southern Company Gas" for additional information on the Southern Company Gas Dispositions.

Operating Revenues

Operating revenues for the successor year ended December 31, 2018 were $3.9 billion, reflecting an $11 million decrease from 2017. 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 period of January 1, 2016 through June 30, 2016, operating revenues were $1.9 billion.

For the successor year ended December 31, 2018, details of operating revenues were as follows:

		(in millions)	*(% change)*
Operating revenues – prior year	$	3,920	
Estimated change resulting from –			
Infrastructure replacement programs and base rate changes		31	0.8
Gas costs and other cost recovery		3	0.1
Weather		13	0.3
Wholesale gas services		138	3.5
Southern Company Gas Dispositions(*)		(228)	(5.8)
Other		32	0.8
Operating revenues – current year	$	3,909	(0.3)%

(*) Includes a $154 million decrease related to natural gas revenues, including alternative revenue programs, and a $74 million decrease related to other revenues. See Note 15 to the financial statements under "Southern Company Gas" for additional information.

Revenues from infrastructure replacement programs and base rate changes increased in 2018 primarily due to a $48 million increase at Nicor Gas, partially offset by a $12 million decrease at Atlanta Gas Light. These amounts include gas distribution operations' continued investments recovered through infrastructure replacement programs and base rate increases less revenue reductions for the impacts of the Tax Reform Legislation. See Note 2 to the financial statements under "Southern Company Gas" for additional information.

Revenues increased due to colder weather in 2018 compared to 2017. See "Heating Degree Days" herein for additional information.

Revenues from wholesale gas services increased in 2018 primarily due to increased commercial activity, partially offset by derivative losses. See "Segment Information – Wholesale Gas Services" herein for additional information.

Other revenues increased in 2018 primarily due to a $15 million increase from the Dalton Pipeline being placed in service in August 2017 and a $14 million increase in Nicor Gas' revenue taxes.

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 negative impact of warmer-than-normal weather, net of hedging.

For the predecessor period of January 1, 2016 through June 30, 2016, natural gas revenues included recovery of $755 million in cost of natural gas and $32 million in net losses from wholesale gas services. Natural gas revenues were partially offset by a $7 million negative impact of warmer-than-normal weather, net of hedging.

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.

Heating Degree Days

During Heating Season, natural gas usage and operating revenues are generally higher. Weather typically does not have a significant net income impact other than during the Heating Season. The following table presents the Heating Degree Days information for Illinois and Georgia, the primary locations where Southern Company Gas' operations are impacted by weather.

	Years Ended December 31,				2018 vs. normal	2018 vs. 2017	2017 vs. 2016
	Normal(*)	**2018**	2017	2016	**colder**	**colder**	colder (warmer)
		(in thousands)					
Illinois	5,813	**6,101**	5,246	5,243	**5.0%**	**16.3%**	0.1 %
Georgia	2,539	**2,588**	1,970	2,175	**1.9%**	**31.4%**	(9.4)%

(*) Normal represents the 10-year average from January 1, 2008 through December 31, 2017 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.

Southern Company Gas hedged its exposure to warmer-than-normal weather in Illinois for gas distribution operations and in Illinois and Georgia for gas marketing services. The remaining impacts of weather on earnings are reflected in the chart below.

	Successor			Predecessor
	Year Ended December 31, 2018	Year Ended December 31, 2017	July 1, 2016 through December 31, 2016	January 1, 2016 through June 30, 2016
		(in millions)		*(in millions)*
Gas Distribution Operations:				
Pre-tax	**$ 2**	$ (4)	$ (1)	$ (7)
After tax	**1**	(2)	(1)	(5)
Gas Marketing Services:				
Pre-tax	**(2)**	(9)	(4)	—
After tax	**(1)**	(5)	(3)	—

Customer Count

The following table provides the number of customers served by Southern Company Gas at December 31, 2018, 2017, and 2016:

	2018	2017	2016
		(in thousands, except market share %)	
Gas distribution operations[a]	**4,248**	4,623	4,586
Gas marketing services			
Energy customers[b]	**697**	774	656
Market share of energy customers in Georgia	**29.0%**	29.2%	29.6%

(a) Includes total customers of approximately 407,000 and 402,000 at December 31, 2017 and 2016, respectively, related to Elizabethtown Gas, Elkton Gas, and Florida City Gas, which were sold in 2018. See Note 15 to the financial statements under "Southern Company Gas – Sale of Elizabethtown Gas and Elkton Gas" and " – Sale of Florida City Gas″ for additional information.

(b) Includes customers in Ohio contracted through an annual auction process to serve for a 12-month period beginning April 1 of each year. At December 31, 2018 and 2017, there were approximately 70,000 and 140,000 contracted customers, respectively. At December 31, 2016, there were no contracted customers.

Southern Company Gas anticipates overall customer growth trends at the remaining four natural gas distribution utilities in gas distribution operations to continue as it expects continued improvement in the new housing market and low natural gas prices. Southern Company Gas uses a variety of targeted marketing programs to attract new customers and to retain existing customers.

Cost of Natural Gas

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 83.2% of the total cost of natural gas for 2018.

Gas marketing services customers are charged for actual and estimated natural gas consumed. Cost of natural gas includes the cost of fuel and associated transportation costs, lost and unaccounted for gas, adjustments to reduce the value of inventories to market value, if applicable, and gains and losses associated with certain derivatives.

For the successor year ended December 31, 2018, cost of natural gas was $1.5 billion, a decrease of $62 million, or 3.9%, compared to 2017 substantially all as a result of the Southern Company Gas Dispositions.

For the successor year ended December 31, 2017, cost of natural gas was $1.6 billion, which reflected an increase in natural gas pricing of 26.3% compared to 2016, partially offset by lower demand for natural gas.

For the successor period of July 1, 2016 through December 31, 2016 and the predecessor period of January 1, 2016 through June 30, 2016, cost of natural gas was $613 million and $755 million, respectively, which reflected low demand for natural gas driven by warm weather during those periods.

Volumes of Natural Gas Sold

The following table details the volumes of natural gas sold during all periods presented.

	Year Ended December 31,			2018 vs. 2017	2017 vs. 2016
	2018	2017	2016	**% Change**	% Change
Gas distribution operations *(mmBtu in millions)*					
Firm	**721**	667	670	**8.1%**	(0.4)%
Interruptible	**95**	95	96	**—%**	(1.0)%
Total	**816**	762	766	**7.1%**	(0.5)%
Wholesale gas services *(mmBtu in millions/day)*					
Daily physical sales	**6.7**	6.4	7.4	**4.7%**	(13.5)%
Gas marketing services *(mmBtu in millions)*					
Firm:					
Georgia	**37**	32	34	**15.6%**	(5.9)%
Illinois	**13**	12	12	**8.3%**	— %
Other	**20**	18	12	**11.1%**	50.0 %
Interruptible large commercial and industrial	**14**	14	14	**—%**	— %
Total	**84**	76	72	**10.5%**	5.6 %

Cost of Other Sales

Cost of other sales related to Pivotal Home Solutions, which was sold on June 4, 2018. See Note 15 to the financial statements under "Southern Company Gas – Sale of Pivotal Home Solutions" for additional information.

Other Operations and Maintenance Expenses

For the successor year ended December 31, 2018, other operations and maintenance expenses increased $36 million, or 3.8%, compared to the prior year. Excluding a $39 million decrease related to the Southern Company Gas Dispositions, other operations and maintenance expenses increased $75 million. This increase was primarily due to a $53 million increase in compensation and benefit costs, including a $12 million one-time increase for the adoption of a new paid time off policy to align with the Southern Company system, a $28 million increase in disposition-related costs, and an $11 million expense for a litigation settlement to facilitate the sale of Pivotal Home Solutions. These increases were partially offset by a $27 million decrease in bad debt expense primarily at Nicor Gas, which was offset by a decrease in revenues as a result of the related regulatory recovery mechanism. See Note 3 to the financial statements under "General Litigation Matters – Southern Company Gas" for additional information on the litigation settlement.

For the successor year ended December 31, 2017 and the successor period of July 1, 2016 through December 31, 2016, other operations and maintenance expenses were $945 million and $480 million, respectively, 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 $452 million and included pipeline compliance and maintenance costs and compensation and benefit costs.

Depreciation and Amortization

For the successor year ended December 31, 2018, depreciation and amortization decreased $1 million, or 0.2%, compared to the prior year. Excluding a $37 million decrease related to the Southern Company Gas Dispositions, depreciation and amortization increased $36 million. This increase was primarily due to continued infrastructure investments at gas distribution operations, partially offset by lower amortization of intangible assets as a result of fair value adjustments in acquisition accounting at gas marketing services.

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 period of January 1, 2016 through June 30, 2016, depreciation and amortization was $206 million and reflected depreciation related to additional assets placed in service at gas distribution operations due to continued investment in infrastructure programs.

See Notes 2 and 15 to the financial statements under "Southern Company Gas – Infrastructure Replacement Programs and Capital Projects" and "Southern Company Merger with Southern Company Gas," 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, 2018, taxes other than income taxes increased $27 million, or 14.7%, compared to the prior year. Excluding a $4 million decrease related to the Southern Company Gas Dispositions, taxes other than income taxes increased $31 million. This increase primarily reflects a $13 million increase in revenue tax expenses as a result of higher natural gas revenues, a $12 million increase in Nicor Gas' invested capital tax that reflects a $7 million credit in 2017 to establish a related regulatory asset, and a $4 million increase in property taxes.

For the successor year ended December 31, 2017, the successor period of July 1, 2016 through December 31, 2016, and the predecessor period of January 1, 2016 through June 30, 2016, taxes other than income taxes were $184 million, $71 million, and $99 million, respectively, which consisted primarily of revenue tax expenses, property taxes, and payroll taxes.

Goodwill Impairment

For the successor year ended December 31, 2018, a goodwill impairment charge of $42 million was recorded in contemplation of the sale of Pivotal Home Solutions. See Notes 1 and 15 to the financial statements under "Goodwill and Other Intangible Assets and Liabilities" and "Southern Company Gas – Sale of Pivotal Home Solutions," respectively, for additional information.

Gain on Dispositions, Net

For the successor year ended December 31, 2018, gain on dispositions, net was $291 million and was associated with the Southern Company Gas Dispositions. The income tax expense on these gains included income tax expense on goodwill not deductible for tax purposes and for which a deferred tax liability had not been recorded previously.

Merger-Related Expenses

There were no Merger-related expenses in the successor years ended December 31, 2018 and 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 period of January 1, 2016 through June 30, 2016, Merger-related expenses were $56 million, including $31 million for financial advisory fees, legal expenses, and other Merger-related costs, and $25 million for additional compensation-related expenses.

See Note 15 to the financial statements under "Southern Company Merger with Southern Company Gas" for additional information.

Earnings from Equity Method Investments

For the successor year ended December 31, 2018, earnings from equity method investments increased $42 million, or 39.6%, compared to the prior year. The increase was primarily due to higher earnings from Southern Company Gas' equity method investment in SNG from new rates effective September 2018 and lower operations and maintenance expenses due to the timing of pipeline maintenance.

For the successor year ended December 31, 2017, earnings from equity method investments were $106 million, reflecting $88 million in earnings from Southern Company Gas' 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 Southern Company Gas' investment in SNG and $4 million in earnings from all other investments.

For the predecessor period of January 1, 2016 through June 30, 2016, earnings from equity method investments were not material.

See Notes 7 and 15 to the financial statements under "Southern Company Gas – Equity Method Investments – SNG" and "Southern Company Gas – Investment in SNG," respectively, for additional information on Southern Company Gas' investment in SNG.

Interest Expense, Net of Amounts Capitalized

For the successor year ended December 31, 2018, interest expense, net of amounts capitalized increased $28 million, or 14.0%, compared to the prior year. The increase was primarily due to $21 million of additional interest expense related to new debt issuances and a $4 million reduction in capitalized interest primarily due to the Dalton Pipeline being placed in service in August 2017.

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 period of January 1, 2016 through June 30, 2016, interest expense, net of amounts capitalized was $96 million, reflecting debt issuances and redemptions during the period and the recognition of previously deferred interest related to regulatory infrastructure programs.

See FUTURE EARNINGS POTENTIAL – "Regulatory Matters – 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 8 to the financial statements for additional information on outstanding debt.

Other Income (Expense), Net

For the successor year ended December 31, 2018, other income (expense), net decreased $43 million, or 97.7%, compared to the prior year. Excluding a $3 million decrease related to the Southern Company Gas Dispositions, other income (expense), net decreased $40 million. This decrease was primarily due to a $23 million increase in charitable donations and a $13 million decrease in gains from the settlement of contractor litigation claims.

For the successor year ended December 31, 2017, other income (expense), net was $44 million and primarily related to a $20 million gain from the settlement of contractor litigation claims, $8 million of AFUDC, a $6 million tax gross-up on contributions

in aid of construction, and $4 million of interest income. See Note 2 to the financial statements under "Southern Company Gas – 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 $12 million and primarily related to the tax gross-up of contributions in aid of construction received from customers.

For the predecessor period of January 1, 2016 through June 30, 2016, other income (expense), net was not material.

Income Taxes

For the successor year ended December 31, 2018, income taxes increased $97 million, or 26.4%, compared to the prior year. Excluding a $329 million increase related to the Southern Company Gas Dispositions, including tax expense on the goodwill for which a deferred tax liability had not been previously provided, income taxes decreased $232 million. This decrease was primarily due to a lower federal income tax rate and the flowback of excess deferred taxes as a result of the Tax Reform Legislation. In addition, 2017 included additional tax expense of $130 million from the revaluation of deferred tax assets associated with the Tax Reform Legislation, the enactment of the State of Illinois income tax legislation, and new income tax apportionment factors in several states.

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 Southern Company Gas' inclusion in the consolidated Southern Company state tax filings.

For the successor period of July 1, 2016 through December 31, 2016 and the predecessor period of January 1, 2016 through June 30, 2016, income taxes were $76 million and $87 million, respectively. The effective tax rates during these periods reflect certain nondeductible Merger-related expenses.

See FUTURE EARNINGS POTENTIAL – "Income Tax Matters" herein and Note 10 to the financial statements for additional information.

Effects of Inflation

Southern Company Gas 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 Southern Company Gas' results of operations has not been substantial in recent years.

Performance and Non-GAAP Measures

Prior to the Merger, Southern Company Gas 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 Southern Company Gas' segments for the predecessor period as EBIT was the primary measure of segment profit or loss for that period. Subsequent to the Merger, Southern Company Gas changed its segment performance measure from EBIT to net income to better align with the performance measure utilized by Southern Company. EBIT for the successor periods presented herein is considered a non-GAAP measure. Southern Company Gas presents 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. Southern Company Gas further believes the presentation of segment EBIT for the successor periods 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, goodwill impairment, gain on dispositions, net, 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 base rate changes, infrastructure replacement programs and capital projects, and 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. Southern Company Gas further believes that utilizing adjusted operating margin at gas pipeline investments, wholesale gas services, and gas marketing services 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, Southern Company Gas' operating performance than net income attributable to Southern Company Gas or operating income as determined in accordance with GAAP. In addition, Southern Company Gas' adjusted operating margin may not be comparable to similarly titled measures of other companies.

Detailed variance explanations of Southern Company Gas' financial performance are provided herein.

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, 2018	Year Ended December 31, 2017	July 1, 2016 through December 31, 2016	January 1, 2016 through June 30, 2016
		(in millions)		*(in millions)*
Operating Income	**$ 915**	$ 660	$ 199	$ 323
Other operating expenses[(a)]	**1,443**	1,630	830	813
Revenue taxes[(b)]	**(111)**	(98)	(31)	(56)
Adjusted Operating Margin	**$ 2,247**	$ 2,192	$ 998	$ 1,080

(a) Includes other operations and maintenance, depreciation and amortization, taxes other than income taxes, goodwill impairment, gain on dispositions, net, and Merger-related expenses.

(b) Nicor Gas' revenue tax expenses, which are passed through directly to customers.

	Successor			Predecessor
	Year Ended December 31, 2018	Year Ended December 31, 2017	July 1, 2016 through December 31, 2016	January 1, 2016 through June 30, 2016
		(in millions)		*(in millions)*
Net Income Attributable to Southern Company Gas	**$ 372**	$ 243	$ 114	$ 131
Net income attributable to noncontrolling interest	**—**	—	—	14
Income taxes	**464**	367	76	87
Interest expense, net of amounts capitalized	**228**	200	81	96
EBIT	**$ 1,064**	$ 810	$ 271	$ 328

Segment Information

Adjusted operating margin, operating expenses, and Southern Company Gas' primary performance metric for each segment are illustrated in the tables below.

	Successor					
	Year ended December 31, 2018			Year ended December 31, 2017		
	Adjusted Operating Margin[a]	**Operating Expenses[a][b]**	**Net Income (Loss)[b]**	Adjusted Operating Margin[a]	Operating Expenses[a]	Net Income (Loss)
	(in millions)			*(in millions)*		
Gas distribution operations	**$ 1,794**	**$ 890**	**$ 334**	$ 1,834	$ 1,189	$ 353
Gas pipeline investments	**32**	**12**	**103**	17	7	(22)
Wholesale gas services	**134**	**64**	**38**	5	56	(57)
Gas marketing services	**263**	**244**	**(40)**	313	200	84
All other	**33**	**131**	**(63)**	35	92	(115)
Intercompany eliminations	**(9)**	**(9)**	**—**	(12)	(12)	—
Consolidated	**$ 2,247**	**$ 1,332**	**$ 372**	$ 2,192	$ 1,532	$ 243

(a) Adjusted operating margin and operating expenses are adjusted for Nicor Gas' revenue tax expenses, which are passed through directly to customers.

(b) Operating expenses for gas distribution operations and gas marketing services include the gain on dispositions, net. Net income for gas distribution operations and gas marketing services includes the gain on dispositions, net and the associated income tax expense. See Note 15 to the financial statements under "Southern Company Gas" for additional information.

	Successor			Predecessor		
	July 1, 2016 through December 31, 2016			January 1, 2016 through June 30, 2016		
	Adjusted Operating Margin[*]	Operating Expenses[*]	Net Income (Loss)	Adjusted Operating Margin[*]	Operating Expenses[*]	EBIT
	(in millions)			*(in millions)*		
Gas distribution operations	$ 817	$ 592	$ 77	$ 911	$ 558	$ 353
Gas pipeline investments	3	2	29	3	—	3
Wholesale gas services	24	26	—	(36)	33	(68)
Gas marketing services	139	112	19	190	81	109
All other	19	71	(11)	16	89	(69)
Intercompany eliminations	(4)	(4)	—	(4)	(4)	—
Consolidated	$ 998	$ 799	$ 114	$ 1,080	$ 757	$ 328

(*) 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 Southern Company Gas' 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 Southern Company Gas 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, operations and maintenance, taxes, and overhead costs, and to earn a reasonable return on its investments.

With the exception of Atlanta Gas Light, Southern Company Gas' 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. Southern Company Gas 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.

On July 1, 2018, a Southern Company Gas subsidiary, Pivotal Utility Holdings, completed the sales of the assets of two of its natural gas distribution utilities, Elizabethtown Gas and Elkton Gas, to South Jersey Industries, Inc. On July 29, 2018, Southern Company Gas and its wholly-owned direct subsidiary, NUI Corporation, completed the sale of Pivotal Utility Holdings, which primarily consisted of Florida City Gas, to NextEra Energy. See Note 15 to the financial statements under "Southern Company Gas" for additional information.

2018 vs. 2017

Net income decreased $19 million, or 5.4%, compared to the prior year, which includes a $40 million decrease in adjusted operating margin, a $299 million decrease in operating expenses, and a $22 million decrease in other income (expense), net resulting in a $237 million increase in EBIT. The decrease in net income also includes a $25 million increase in interest expense, net of amounts capitalized and a $231 million increase in income tax expense.

Excluding a $90 million decrease attributable to the utilities sold during 2018, adjusted operating margin increased $50 million, which primarily reflects additional revenue from infrastructure investments and colder weather in 2018, partially offset by lower rates and revenue deferrals for regulatory liabilities associated with the Tax Reform Legislation impacts. Excluding a $391 million decrease attributable to the utilities sold during 2018 that includes the related gains on the sales, operating expenses increased $92 million. This increase reflects $40 million of additional depreciation primarily due to additional assets placed in service, $37 million of additional other operations and maintenance expenses primarily due to increased compensation and benefit costs, partially offset by a decrease in bad debt expense, and $15 million of additional taxes other than income taxes primarily due to a $12 million increase in Nicor Gas' invested capital tax. Excluding a $3 million decrease attributable to the utilities sold during 2018, other income (expense), net decreased $20 million, which primarily reflects a $13 million decrease in gains from the settlement of contractor litigation claims. The increase in interest expense reflects $14 million of additional interest expense primarily from the issuance of first mortgage bonds at Nicor Gas. Excluding a $290 million decrease attributable to the utilities sold in 2018, income tax expense decreased $59 million, primarily due to lower pretax earnings, a lower federal income tax rate, and the flowback of excess deferred taxes as a result of the Tax Reform Legislation.

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 $39 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 in August 2017 and November 2017. Income tax expense includes a $22 million benefit as a result of the Tax Reform Legislation.

See Note 2 to the financial statements under "Southern Company Gas – PRP Settlement" for additional information on contractor litigation claims. See FINANCIAL CONDITION AND LIQUIDITY – "Financing Activities" herein and Note 8 to the financial statements for additional information on debt issuances. See FUTURE EARNINGS POTENTIAL – "Income Tax Matters" herein and Note 10 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, $592 million in operating expenses, and $8 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 15 to the financial statements under "Southern Company Merger with Southern Company Gas" for additional information.

Predecessor Period of January 1, 2016 through June 30, 2016

EBIT of $353 million includes $911 million in adjusted operating margin and $558 million in operating expense. 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.

Gas Pipeline Investments

Gas pipeline investments consists primarily of joint ventures in natural gas pipeline investments including SNG, Atlantic Coast Pipeline, PennEast Pipeline, and Dalton Pipeline. See Note 7 to the financial statements under "Southern Company Gas" for additional information.

2018 vs. 2017

Net income increased $125 million compared to the prior year, which includes a $15 million increase in adjusted operating margin primarily due to the Dalton Pipeline being placed in service in August 2017, a $5 million increase in operating expenses primarily due to increased depreciation and property tax expense related to the Dalton Pipeline, and a $42 million increase in earnings from equity method investments primarily at SNG, resulting in a $52 million increase in EBIT. The increase in net income also includes an $8 million increase in interest expense, net of amounts capitalized primarily due to a reduction in capitalized interest after the Dalton Pipeline was placed in service and an $81 million decrease in income tax expense primarily due to a lower federal income tax rate in 2018 and additional tax expense recorded in 2017 associated with the Tax Reform Legislation, partially offset by higher pretax earnings.

Successor Year Ended December 31, 2017

Net loss of $22 million includes $17 million in adjusted operating margin, $7 million in operating expenses, and $103 million in earnings from equity method investments, consisting primarily of Southern Company Gas' 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, which resulted in EBIT of $113 million. Also included in net income are $26 million in interest expense, net of amounts capitalized and $109 million in income tax expense. Income tax expense includes $66 million resulting from the revaluation of deferred income tax assets associated with the Tax Reform Legislation and $7 million related to the allocation of new income tax apportionment factors in several states resulting from Southern Company Gas' inclusion in the consolidated Southern Company state tax filings. See FUTURE EARNINGS POTENTIAL – "Income Tax Matters" herein and Note 10 to the financial statements for additional information.

Successor Period of July 1, 2016 through December 31, 2016

Net income of $29 million includes $3 million in adjusted operating margin, $2 million in operating expenses, and $59 million in earnings from equity method investments, consisting primarily of Southern Company Gas' 2016 acquired equity interest in SNG, resulting in EBIT of $60 million. Also included in net income are $10 million in interest expense, net of amounts capitalized and $21 million in income tax expense.

Predecessor Period of January 1, 2016 through June 30, 2016

Earnings before interest and taxes for the predecessor period of January 1, 2016 through June 30, 2016 was $3 million.

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. Southern Company Gas 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. Operating expenses primarily reflect employee compensation and benefits.

2018 vs. 2017

Net income increased $95 million, or 166.7%, compared to the prior year, which includes a $129 million increase in adjusted operating margin, an $8 million increase in operating expenses, a $1 million increase in interest income, and a $21 million decrease in other income (expense), net resulting in a $101 million increase in EBIT. The increase in net income also includes a $2 million increase in interest expense, net of amounts capitalized and a $4 million increase in income tax expense. Details of the increase in adjusted operating margin are provided in the table below. The increase in operating expenses primarily reflects higher

compensation and benefit expense. The decrease in other income (expense), net primarily reflects increased charitable donations. The increase in income tax expense reflects higher pretax earnings, partially offset by a lower federal income tax rate.

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 10 to the financial statements for additional information.

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.

The following table illustrates the components of wholesale gas services' adjusted operating margin for the periods presented:

	Successor			Predecessor
	Year Ended December 31, 2018	Year Ended December 31, 2017	July 1, 2016 through December 31, 2016	January 1, 2016 through June 30, 2016
		(in millions)		*(in millions)*
Commercial activity recognized	**$ 254**	$ 116	$ (15)	$ 34
Gain (loss) on storage derivatives	**9**	23	(20)	(38)
Gain (loss) on transportation and forward commodity derivatives	**(119)**	(113)	64	(31)
LOCOM adjustments, net of current period recoveries	**(7)**	—	—	(1)
Purchase accounting adjustments to fair value inventory and contracts	**(3)**	(21)	(5)	—
Adjusted operating margin	**$ 134**	$ 5	$ 24	$ (36)

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. The increase in commercial activity in 2018 compared to the prior year was primarily due to natural gas price volatility that was generated by favorable weather and a corresponding increase in power generation volumes coupled with decreased natural gas supply.

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 Southern Company Gas' 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. Forward storage or time spreads applicable to the locations of wholesale gas services' specific storage positions in 2018 resulted in storage derivative gains. Transportation and forward commodity losses in 2018 are primarily the result of widening transportation spreads due to favorable weather, which impacted forward prices at natural gas receipt and delivery points primarily in the Northeast and Midwest regions.

The natural gas that Southern Company Gas purchases and injects into storage is accounted for at the LOCOM value utilizing gas daily or spot prices at the end of the year. A LOCOM adjustment, net of current period recoveries of $7 million, was recorded during 2018 and 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, and exclude estimated profit sharing under 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, 2018. 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		
	Total storage[a]	Expected net operating losses[b]	Physical Transportation Transactions – Expected Net Operating Gains[c]
	(in mmBtu in millions)	*(in millions)*	*(in millions)*
2019	48	$ (8)	$ 12
2020 and thereafter	—	—	107
Total at December 31, 2018	48	$ (8)	$ 119

(a) At December 31, 2018, the WACOG of wholesale gas services' expected natural gas withdrawals from storage was $2.90 per mmBtu.

(b) Represents expected operating losses 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.

(c) Represents the periods associated with the transportation derivative net gains during which the derivatives will be settled and the physical transportation transactions will occur that offset the derivative gains and losses that were previously recognized.

Gas Marketing Services

Gas marketing services provides energy-related products and services to natural gas markets and participants in customer choice programs that were approved in various states to increase competition. These programs allow customers to choose their natural gas supplier while the local distribution utility continues to provide distribution and transportation services. 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.

On June 4, 2018, Southern Company Gas completed the sale of Pivotal Home Solutions to American Water Enterprises LLC. See Note 15 under "Southern Company Gas – Sale of Pivotal Home Solutions" for additional information.

2018 vs. 2017

Net income decreased $124 million, or 147.6%, compared to the prior year, which includes a $50 million decrease in adjusted operating margin, a $44 million increase in operating expenses, and a $1 million increase in other income (expense), net resulting in a $93 million decrease in EBIT. The decrease in net income also includes a $1 million increase in interest expense, net of amounts capitalized and a $30 million increase in income tax expense.

Excluding a $57 million decrease attributable to Pivotal Home Solutions, adjusted operating margin increased $7 million, which primarily reflects colder weather in 2018, customer growth, and favorable retail price spreads. Excluding a $42 million increase attributable to Pivotal Home Solutions that includes the loss on disposition and the goodwill impairment charge, operating expense increased $2 million. Excluding a $39 million increase attributable to Pivotal Home Solutions, income tax expense decreased $9 million driven by a lower federal income tax rate, partially offset by higher pretax earnings.

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 10 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 expenses 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 15 to the financial statements under "Southern Company Merger with Southern Company Gas" 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.

All Other

All other includes Southern Company Gas' storage and fuels operations and its 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.

2018 vs. 2017

Net loss decreased $52 million, or 45.2%, compared to the prior year, which includes a $2 million decrease in adjusted operating margin, a $39 million increase in operating expenses, a $3 million increase in interest income, and a $5 million decrease in other income (expense), net resulting in a $43 million decrease in EBIT. The decrease in net loss also includes an $8 million decrease in interest expense, net of amounts capitalized and an $87 million decrease in income tax expense. The increase in operating expenses primarily reflects a $28 million increase in disposition-related costs and a $12 million increase in compensation expenses resulting from the adoption of a new paid time off policy. The decrease in income tax expense primarily reflects the 2017 increase in income tax expense related to the revaluation of deferred tax assets associated with the Tax Reform Legislation, the enactment of the State of Illinois income tax legislation, new income tax apportionment factors in several states, and a lower federal income tax rate in 2018. The decrease also reflects lower pretax earnings in 2018 compared to 2017.

Successor Year Ended December 31, 2017

Net loss of $115 million includes $35 million in adjusted operating margin and $92 million in operating expenses. Operating expenses included $26 million of integration-related costs. Interest expense, net of amounts capitalized was $9 million due to intercompany promissory notes that were executed in December 2016. Income tax expense was $56 million and includes $46 million resulting from the revaluation of deferred tax assets associated with the Tax Reform Legislation and $30 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 Southern Company Gas' inclusion in the consolidated Southern Company state tax filings, partially offset by income tax benefit on the pre-tax loss. See FINANCIAL CONDITION AND LIQUIDITY – "Financing Activities" herein for additional financing information and FUTURE EARNINGS POTENTIAL – "Income Tax Matters" herein and Note 10 to the financial statements for additional information.

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 Period of January 1, 2016 through June 30, 2016

For the predecessor period of January 1, 2016 through June 30, 2016, operating expenses included Merger-related expenses of $56 million. 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 15 to the financial statements under "Southern Company Merger with Southern Company Gas" for additional information.

Segment Reconciliations

Reconciliations of net income attributable to Southern Company Gas to EBIT for the years ended December 31, 2018 and 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 16 to the financial statements under "Southern Company Gas" for additional segment information.

	Successor						
	Year Ended December 31, 2018						
	Gas Distribution Operations	**Gas Pipeline Investments**	**Wholesale Gas Services**	**Gas Marketing Services**	**All Other**	**Intercompany Elimination**	**Consolidated**
	(in millions)						
Net Income (Loss) Attributable to Southern Company Gas	**$ 334**	**$ 103**	**$ 38**	**$ (40)**	**$ (63)**	**$ —**	**$ 372**
Income taxes (benefit)	**409**	**28**	**4**	**54**	**(31)**	**—**	**464**
Interest expense, net of amounts capitalized	**178**	**34**	**9**	**6**	**1**	**—**	**228**
EBIT	**$ 921**	**$ 165**	**$ 51**	**$ 20**	**$ (93)**	**$ —**	**$ 1,064**

	Successor						
	Year Ended December 31, 2017						
	Gas Distribution Operations	Gas Pipeline Investments	Wholesale Gas Services	Gas Marketing Services	All Other	Intercompany Elimination	Consolidated
	(in millions)						
Net Income (Loss) Attributable to Southern Company Gas	$ 353	$ (22)	$ (57)	$ 84	$ (115)	$ —	$ 243
Income taxes	178	109	—	24	56	—	367
Interest expense, net of amounts capitalized	153	26	7	5	9	—	200
EBIT	$ 684	$ 113	$ (50)	$ 113	$ (50)	$ —	$ 810

	Successor						
	July 1, 2016 through December 31, 2016						
	Gas Distribution Operations	Gas Pipeline Investments	Wholesale Gas Services	Gas Marketing Services	All Other	Intercompany Elimination	Consolidated
	(in millions)						
Net Income (Loss) Attributable to Southern Company Gas	$ 77	$ 29	$ —	$ 19	$ (11)	$ —	$ 114
Income taxes (benefit)	51	21	(3)	7	—	—	76
Interest expense, net of amounts capitalized	105	10	3	1	(38)	—	81
EBIT	$ 233	$ 60	$ —	$ 27	$ (49)	$ —	$ 271

	Successor						
	Year Ended December 31, 2018						
	Gas Distribution Operations	**Gas Pipeline Investments**	**Wholesale Gas Services**	**Gas Marketing Services**	**All Other**	**Intercompany Elimination**	**Consolidated**
	(in millions)						
Operating Income (Loss)	**$ 904**	**$ 20**	**$ 70**	**$ 19**	**$ (98)**	**$ —**	**$ 915**
Other operating expenses[(a)]	**1,001**	**12**	**64**	**244**	**131**	**(9)**	**1,443**
Revenue tax expense[(b)]	**(111)**	**—**	**—**	**—**	**—**	**—**	**(111)**
Adjusted Operating Margin	**$ 1,794**	**$ 32**	**$ 134**	**$ 263**	**$ 33**	**$ (9)**	**$ 2,247**

	Successor						
	Year Ended December 31, 2017						
	Gas Distribution Operations	Gas Pipeline Investments	Wholesale Gas Services	Gas Marketing Services	All Other	Intercompany Elimination	Consolidated
	(in millions)						
Operating Income (Loss)	$ 645	$ 10	$ (51)	$ 113	$ (57)	$ —	$ 660
Other operating expenses[(a)]	1,287	7	56	200	92	(12)	1,630
Revenue tax expense[(b)]	(98)	—	—	—	—	—	(98)
Adjusted Operating Margin	$ 1,834	$ 17	$ 5	$ 313	$ 35	$ (12)	$ 2,192

	Successor						
	July 1, 2016 through December 31, 2016						
	Gas Distribution Operations	Gas Pipeline Investments	Wholesale Gas Services	Gas Marketing Services	All Other	Intercompany Elimination	Consolidated
	(in millions)						
Operating Income (Loss)	$ 225	$ 1	$ (2)	$ 27	$ (52)	$ —	$ 199
Other operating expenses[(a)]	623	2	26	112	71	(4)	830
Revenue tax expense[(b)]	(31)	—	—	—	—	—	(31)
Adjusted Operating Margin	$ 817	$ 3	$ 24	$ 139	$ 19	$ (4)	$ 998

	Predecessor						
	January 1, 2016 through June 30, 2016						
	Gas Distribution Operations	Gas Pipeline Investments	Wholesale Gas Services	Gas Marketing Services	All Other	Intercompany Elimination	Consolidated
	(in millions)						
Operating Income (Loss)	$ 353	$ 3	$ (69)	$ 109	$ (73)	$ —	$ 323
Other operating expenses[a]	614	—	33	81	89	(4)	813
Revenue tax expense[b]	(56)	—	—	—	—	—	(56)
Adjusted Operating Margin	$ 911	$ 3	$ (36)	$ 190	$ 16	$ (4)	$ 1,080

(a) Includes other operations and maintenance, depreciation and amortization, taxes other than income taxes, goodwill impairment, gain on dispositions, net, 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 Southern Company Gas Dispositions are expected to materially decrease future earnings and cash flows to Southern Company Gas. For the year ended December 31, 2018, pre-tax earnings attributable to these dispositions were $297 million, which includes a $291 million gain on dispositions, net and a $42 million goodwill impairment. For the year ended December 31, 2017, net income attributable to these dispositions was $71 million, which included additional tax expense of $16 million associated with the Tax Reform Legislation. 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, these results are not necessarily indicative of the results to be expected for any other period. The level of Southern Company Gas' future earnings depends on numerous factors that affect the opportunities, challenges, and risks of Southern Company Gas' primary business of natural gas distribution and its complementary businesses in the gas pipeline investments, wholesale gas services, and gas marketing services sectors. These factors include Southern Company Gas' ability to maintain constructive regulatory environments that allow for the timely recovery of prudently-incurred costs, the completion and subsequent operation of ongoing infrastructure and other construction projects, creditworthiness of customers, its ability to optimize its transportation and storage positions, and its ability to re-contract storage rates at favorable prices.

Future earnings will be driven 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 Southern Company Gas' 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 Southern Company Gas' customer rates, its 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 Southern Company Gas' 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. See "FERC Matters" herein for additional information on permitting challenges experienced by the Atlantic Coast Pipeline. 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, 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.

As part of its business strategy, Southern Company Gas regularly considers and evaluates joint development arrangements as well as acquisitions and dispositions of businesses and assets.

- On June 4, 2018, Southern Company Gas completed the stock sale of Pivotal Home Solutions to American Water Enterprises LLC. Southern Company Gas and American Water Enterprises LLC entered into a transition services

agreement whereby Southern Company Gas provided certain administrative and operational services through November 4, 2018.

- On July 1, 2018, a Southern Company Gas subsidiary, Pivotal Utility Holdings, completed the sales of the assets of two of its natural gas distribution utilities, Elizabethtown Gas and Elkton Gas, to South Jersey Industries, Inc. Southern Company Gas and South Jersey Industries, Inc. entered into transition services agreements whereby Southern Company Gas will provide certain administrative and operational services through no later than July 31, 2020.
- On July 29, 2018, Southern Company Gas and its wholly-owned direct subsidiary, NUI Corporation, completed the stock sale of Pivotal Utility Holdings, which primarily consisted of Florida City Gas, to NextEra Energy. Southern Company Gas and NextEra Energy entered into a transition services agreement whereby Southern Company Gas will provide certain administrative and operational services through no later than July 29, 2020.

See OVERVIEW – "Merger, Acquisition, and Disposition Activities" herein and Note 15 to the financial statements under "Southern Company Gas" for additional information on these dispositions. See BUSINESS – "Seasonality" in Item 1, RISK FACTORS in Item 1A, and OVERVIEW – "Seasonality of Results" for additional information on seasonality.

Environmental Matters

Southern Company Gas' 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. Southern Company Gas 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 customer rates. The ultimate impact of the environmental laws and regulations discussed herein 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 Southern Company Gas' 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 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/or 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.

Environmental Remediation

Southern Company Gas is subject to environmental remediation liabilities associated with 40 former MGP sites in four different states. Southern Company Gas 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. An accrued environmental remediation liability of $294 million was included in the balance sheets at December 31, 2018, of which $26 million is expected to be incurred over the next 12 months. The accrued environmental remediation liability decreased at December 31, 2018 primarily due to the disposition of $85 million that related to Elizabethtown Gas. The natural gas distribution utilities in Illinois and Georgia have 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 and Note 3 to the financial statements under "Environmental Remediation" 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. The EPA and the Corps are expected to publish a final rule in 2019 to replace the 2015 WOTUS definition. The impact of any changes to the 2015 WOTUS rule will depend on the content of this final rule and the outcome of any legal challenges.

Global Climate Issues

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, Southern

Company Gas' 2017 GHG emissions were approximately 0.6 million metric tons of CO_2 equivalent. The preliminary estimate of Southern Company Gas' 2018 GHG emissions on the same basis is approximately 0.6 million metric tons of CO_2 equivalent.

FERC Matters

Southern Company Gas is involved in two significant pipeline construction projects within gas pipeline investments. 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. The following table provides an overview of these pipeline projects.

	Miles of Pipe	Capital Expenditures[a]	Ownership Percentage
		(in millions)	
Atlantic Coast Pipeline[b]	594	$ 350-390	5%
PennEast Pipeline[c]	118	$ 276	20%

(a) Represents Southern Company Gas' expected total capital expenditures, excluding AFUDC, at completion, which may change.

(b) In 2014, Southern Company Gas 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. In August 2017, the Atlantic Coast Pipeline received FERC approval.

(c) In 2014, Southern Company Gas 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. Southern Company Gas 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 received FERC approval.

Work continues with state and federal agencies to obtain the required permits to begin construction on the PennEast Pipeline. Any material delays may impact forecasted capital expenditures and the expected in-service date.

The Atlantic Coast Pipeline has experienced challenges to its permits since construction began in 2018. During the third and fourth quarters 2018, a FERC stop work order, together with delays in obtaining permits necessary for construction and construction delays due to judicial actions, impacted the cost and schedule for the project. As a result, total project cost estimates have increased from between $6.0 billion and $6.5 billion to between $7.0 billion and $7.8 billion, excluding financing costs. Southern Company Gas' share of the total project costs is 5% and Southern Company Gas' investment at December 31, 2018 totaled $83 million. The operator of the joint venture currently expects to achieve a late 2020 in-service date for at least key segments of the Atlantic Coast Pipeline, while the remainder may extend into early 2021. Southern Company Gas has evaluated the recoverability of its investment and determined there was no impairment as of December 31, 2018. Abnormal weather, work delays (including due to judicial or regulatory action), and other conditions may result in additional cost or schedule modifications, which could result in an impairment of Southern Company Gas' investment and could have a material impact on Southern Company Gas' financial statements.

The ultimate outcome of these matters cannot be determined at this time. See Notes 7 and 9 to the financial statements under "Southern Company Gas – Equity Method Investments" and "Guarantees," respectively, for additional information on these pipeline projects.

In August 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. Southern Company Gas has a 50% ownership interest in the Dalton Pipeline. See Note 5 to the financial statements under "Joint Ownership Agreements" for additional information.

On November 16, 2018, SNG completed its purchase of Georgia Power's natural gas lateral pipeline serving Plant McDonough Units 4 through 6 at net book value, as approved by the Georgia PSC on January 16, 2018. SNG expects to pay $142 million to Georgia Power in the first quarter 2020. During the interim period, Georgia Power will receive a discounted shipping rate to reflect the delayed consideration. Southern Company Gas' portion of the expected capital expenditures for the purchase of this pipeline and additional construction is $122 million.

Regulatory Matters

Utility Regulation and Rate Design

The natural gas distribution utilities are subject to regulations and oversight by their respective state regulatory agencies. 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.

Georgia Rate Adjustment Mechanism (GRAM)

In February 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 including the Integrated Vintage Plastic Replacement Program (i-VPR) to replace aging plastic pipe and the Integrated System Reinforcement Program (i-SRP) to upgrade Atlanta Gas Light's distribution system and LNG facilities in Georgia continue under GRAM and the recovery of and return on the infrastructure program investments are included in annual base rate adjustments. The Georgia PSC reviews Atlanta Gas Light's performance annually under GRAM. See "Rate Proceedings" herein for additional information.

Pursuant to the GRAM approval, Atlanta Gas Light and the staff of the Georgia PSC agreed to a variation of the Integrated Customer Growth Program to extend pipeline facilities to serve customers in areas without pipeline access and create new economic development opportunities in Georgia, which was formerly part of the 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.

PRP

In 2015, 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 and the estimated amounts to be earned under the program through 2025. The unrecovered balance is the result of the continued revenue requirement earned under the program offset by the existing and incremental PRP surcharges. The under recovered balance at December 31, 2018 was $171 million, including $95 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 "Rate Proceedings" and "Unrecognized Ratemaking Amounts" herein for additional information.

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. Southern Company Gas has various mechanisms, such as weather normalization mechanisms and weather derivative instruments, that limit exposure to weather changes within typical ranges in these utilities' respective service territories.

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. With the exception of Nicor Gas, the utilities have decoupled regulatory mechanisms that Southern Company Gas 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 Southern Company Gas' revenues or net income, but will affect cash flows. See Note 2 to the financial statements under "Southern Company Gas" for additional information.

The following table provides regulatory information for Southern Company Gas' natural gas distribution utilities:

	Nicor Gas	Atlanta Gas Light	Virginia Natural Gas	Chattanooga Gas
Authorized ROE[(a)(b)]	9.80%	10.75%	9.50%	9.80%
Weather normalization mechanisms[(c)]			✓	✓
Decoupled, including straight-fixed-variable rates[(d)]		✓	✓	
Regulatory infrastructure program rates[(e)(f)]	✓		✓	
Bad debt rider[(g)]	✓		✓	✓
Energy efficiency plan[(h)]	✓		✓	
Year of last rate decision[(i)]	2018	2018	2018	2018

(a) Represents the authorized ROE, or the midpoint of the authorized ROE range, at December 31, 2018.

(b) The authorized ROE range for Atlanta Gas Light and Virginia Natural Gas was 10.55% - 10.95% and 9.00% - 10.00%, respectively, at December 31, 2018.

(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) Recovery of program costs at Atlanta Gas Light was incorporated in GRAM, which the Georgia PSC approved in February 2017. See "Infrastructure Replacement Programs and Capital Projects – Atlanta Gas Light" herein for additional information.

(g) The recovery (refund) of bad debt expense over (under) an established benchmark expense. Nicor Gas, Virginia Natural Gas, and Chattanooga Gas recover the gas portion of bad debt expense through their purchased gas adjustment mechanisms.

(h) Recovery of costs associated with plans to achieve specified energy savings goals.

(i) See "Rate Proceedings" herein and Note 2 to the financial statements under "Southern Company Gas – Rate Proceedings" for additional information.

Infrastructure Replacement Programs and Capital Projects

Southern Company Gas 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. In addition to capital expenditures recovered through base rates by each of the natural gas distribution utilities, Nicor Gas and Virginia Natural Gas have separate rate riders that provide timely recovery of capital expenditures for specific infrastructure replacement programs. Total capital expenditures incurred during 2018 for gas distribution operations were $1.4 billion, including $97 million related to Elizabethtown Gas, Elkton Gas, and Florida City Gas, which were sold in 2018.

The following table and discussions provide updates on the infrastructure replacement programs and capital projects at the natural gas distribution utilities at December 31, 2018. These programs are risk-based and designed to update and replace cast iron, bare steel, and mid-vintage plastic materials or expand Southern Company Gas' distribution systems to improve reliability and meet operational flexibility and growth. The anticipated expenditures for these programs in 2019 are quantified in the discussion below.

Utility	Program	Recovery	Expenditures in 2018	Expenditures Since Project Inception	Pipe Installed Since Project Inception	Scope of Program	Program Duration	Last Year of Program
			(in millions)		*(miles)*	*(miles)*	*(years)*	
Nicor Gas	Investing in Illinois(*)	Rider	$ 409	$ 1,316	706	1,500	9	2023
Virginia Natural Gas	Steps to Advance Virginia's Energy (SAVE and SAVE II)	Rider	40	196	287	496	10	2021
Total			$ 449	$ 1,512	993	1,996		

(*) Includes replacement of pipes, compressors, and transmission mains along with other improvements such as new meters. Scope of program miles is an estimate and subject to change.

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, subject to annual review. Nicor Gas expects to place into service $373 million of qualifying projects under Investing in Illinois in 2019.

In conjunction with the base rate case order issued by the Illinois Commission on January 31, 2018, Nicor Gas is recovering program costs incurred prior to December 31, 2017 through base rates. Nicor Gas has requested that the program costs incurred subsequent to December 31, 2017, which are currently being recovered through a separate rider, be addressed in the base rate case filed November 9, 2018. See "Rate Proceedings" herein for additional information.

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. In 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 2019.

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 in December 2017, Virginia Natural Gas is recovering program costs incurred prior to September 1, 2017 through base rates. Program costs incurred subsequent to September 1, 2017 are currently recovered through a separate rider and are subject to future base rate case proceedings.

Atlanta Gas Light

As discussed previously under "Utility Regulation and Rate Design," i-SRP and i-VPR will continue under GRAM and the recovery of and return on current and future capital investments under the STRIDE program will be included in annual base rate adjustments.

The orders for the STRIDE program 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 program, net of any related cost savings. The regulatory asset represents incurred program costs that will be collected through GRAM. 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.

Rate Proceedings

Nicor Gas

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%.

On April 19, 2018, the Illinois Commission approved Nicor Gas' variable income tax adjustment rider. This rider provides for refund or recovery of changes in income tax expense that result from income tax rates that differ from those used in Nicor Gas' last rate case. Customer refunds, via bill credits, related to the impacts of the Tax Reform Legislation from January 25, 2018 through May 4, 2018 began on July 1, 2018 and are expected to conclude in the second quarter 2019.

On May 2, 2018, the Illinois Commission approved Nicor Gas' rehearing request for revised base rates to incorporate the reduction in the federal income tax rate as a result of the Tax Reform Legislation. The resulting decrease of approximately $44 million in annual base rate revenues became effective May 5, 2018. Nicor Gas' previously-authorized capital structure and ROE of 9.80% were not addressed in the rehearing and remain unchanged.

On November 9, 2018, Nicor Gas filed a general base rate case with the Illinois Commission requesting a $230 million increase in annual base rate revenues. The requested increase is based on a projected test year for the 12-month period ending September 30, 2020, a ROE of 10.6%, and an increase in the equity ratio from 52.0% to 54.0% to address the negative cash flow and credit metric impacts of the Tax Reform Legislation. The Illinois Commission is expected to rule on the requested increase within the 11-month statutory time limit, after which rate adjustments will be effective. The ultimate outcome of this matter cannot be determined at this time.

Atlanta Gas Light

On February 23, 2018, Atlanta Gas Light revised its annual base rate filing to reflect the impacts of the Tax Reform Legislation and requested a $16 million rate reduction in 2018. On May 15, 2018, the Georgia PSC approved a stipulation for Atlanta Gas Light's annual base rates to remain at the 2017 level for 2018 and 2019, with customer credits of $8 million in each of July 2018 and October 2018 to reflect the impacts of the Tax Reform Legislation. The Georgia PSC maintained Atlanta Gas Light's previously authorized earnings band based on a ROE between 10.55% and 10.95% and increased the allowed equity ratio by 4% to an equity ratio of 55% to address the negative cash flow and credit metric impacts of the Tax Reform Legislation. Additionally, Atlanta Gas Light is required to file a traditional base rate case on or before June 1, 2019 for rates effective January 1, 2020.

Atlanta Gas Light's recovery of the previously unrecovered PRP revenue through 2014, as well as the mitigation costs associated with the PRP that were not previously included in its rates, were included in GRAM. In connection with the GRAM approval, the last monthly PRP surcharge increase became effective March 1, 2017.

Virginia Natural Gas

On December 17, 2018, the Virginia Commission approved Virginia Natural Gas' annual information form filing, which reduced annual base rates by $14 million effective January 1, 2019 due to lower tax expense as a result of the lower corporate income tax rate and the impact of the flowback of excess deferred income taxes. This approval also requires Virginia Natural Gas to issue customer refunds, via bill credits, for the entire $14 million which was deferred as a regulatory liability, current, on the balance sheet at December 31, 2018. These customer refunds are expected to be completed in the first quarter 2019.

Affiliate Asset Management Agreements

With the exception of Nicor Gas, the natural gas distribution utilities use asset management agreements with an affiliate, 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 natural gas distribution 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.

Upon closing the sales of Elizabethtown Gas and Elkton Gas, an affiliate of South Jersey Industries, Inc. assumed the asset management agreements with wholesale gas services for Elizabethtown Gas and Elkton Gas. The sale of Pivotal Utility Holdings to NextEra Energy did not impact the asset management agreement between Sequent and Florida City Gas, which will remain in

effect until March 31, 2019. See Note 15 to the financial statements under "Southern Company Gas " for additional information on these dispositions.

Each agreement provides for Sequent to make payments to the natural gas distribution utility 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, 2018, Sequent made sharing payments to the natural gas distribution utilities under these agreements totaling $425 million.

The following table provides payments made by Sequent to the remaining natural gas distribution utilities under these agreements during the last three years:

	Successor			Predecessor	
	Year Ended December 31,	Year Ended December 31,	July 1, 2016 through December 31,	January 1, 2016 through June 30,	
	2018	2017	2016	2016	Expiration Date
		(in millions)		*(in millions)*	
Virginia Natural Gas	**$ 11**	$ 6	$ 2	$ 9	March 2019
Atlanta Gas Light	**9**	4	1	6	March 2020
Chattanooga Gas	**1**	1	—	1	March 2021
Total(*)	**$ 21**	$ 11	$ 3	$ 16	

(*) Payments made to Elizabethtown Gas, Elkton Gas, and Florida City Gas, which were sold in July 2018, were $14 million and $12 million for the successor years ended December 31, 2018 and 2017, respectively, $3 million for the successor period of July 1, 2016 through December 31, 2016, and $13 million for the predecessor period of January 1, 2016 through June 30, 2016. See Note 15 to the financial statements under "Southern Company Gas" for additional information on these dispositions.

energySMART

The Illinois Commission approved Nicor Gas' energySMART program, which includes energy efficiency program offerings and therm reduction goals. Through December 31, 2017, Nicor Gas spent $107 million of the initial authorized expenditure of $113 million. A new program began on January 1, 2018, with an additional authorized expenditure of $160 million through 2021. Through December 31, 2018, Nicor Gas had spent $29 million.

Unrecognized Ratemaking Amounts

The following table illustrates Southern Company Gas' 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 regulatory infrastructure programs. These amounts will be recognized as revenues in Southern Company Gas' financial statements in the periods they are billable to customers, the majority of which will be recovered by 2025.

	December 31, 2018	December 31, 2017
	(in millions)	
Atlanta Gas Light	**$ 95**	$ 104
Virginia Natural Gas	**11**	11
Nicor Gas	**4**	2
Total	**$ 110**	$ 117

Income Tax Matters

Federal Tax Reform Legislation

In December 2017, the Tax Reform Legislation was signed into law and became effective on January 1, 2018. The Tax Reform Legislation, among other things, reduced the federal corporate income tax rate to 21%, retained normalization provisions for public utility property and existing renewable energy incentives, and repealed the corporate alternative minimum tax. 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 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. See Note 10 to the financial statements for information on Southern Company's joint consolidated income tax allocation agreement.

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 provided 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 Gas considered all amounts recorded in the financial statements as a result of the Tax Reform Legislation "provisional" as discussed in SAB 118 and subject to revision prior to filing its 2017 tax return in the fourth quarter 2018. Southern Company Gas recognized tax benefits of $3 million and tax expense of $93 million in 2018 and 2017, respectively, for a total net tax expense of $90 million as a result of the Tax Reform Legislation. In addition, in total, Southern Company Gas recorded a $781 million increase in regulatory liabilities as a result of the Tax Reform Legislation and $4 million of stranded excess deferred tax balances in AOCI at December 31, 2017 were adjusted through retained earnings in 2018. As of December 31, 2018, Southern Company Gas considered the measurement of impacts from the Tax Reform Legislation on deferred income tax assets and liabilities, primarily due to the impact of the reduction of the corporate income tax rate, to be complete.

However, the IRS continues to issue regulations that provide further interpretation and guidance on the law and each state's adoption of the provisions contained in the Tax Reform Legislation remains uncertain. In addition, 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. The ultimate impact of these matters cannot be determined at this time. See Note 2 to the financial statements under "Southern Company Gas – Rate Proceedings" for additional information on the natural gas distribution utilities' rate filings to reflect the impacts of the Tax Reform Legislation. Also see FINANCIAL CONDITION AND LIQUIDITY – "Credit Rating Risk" herein and Note 10 to the financial statements under "Current and Deferred Income Taxes" for additional information.

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 $40 million for the 2018 tax year and approximately $20 million for the 2019 tax year. See Note 10 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.

Other Matters

Southern Company Gas is involved in various other matters being litigated and regulatory matters that could affect future earnings. In addition, Southern Company Gas is subject to certain claims and legal actions arising in the ordinary course of business.

Southern Company Gas is involved in litigation relating to an incident that occurred in one of its prior service territories that resulted in several deaths, injuries, and property damage. Southern Company Gas has resolved all claims for personal injuries or death, but it is continuing to defend litigation seeking to recover alleged property damages. Southern Company Gas has insurance that provides full coverage of the expected financial exposure in excess of $11 million per incident. During the successor period ended December 31, 2016, Southern Company Gas recorded reserves for substantially all of its potential exposure from these cases.

The ultimate outcome of this matter 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 Notes 2 and 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 Gas' financial statements. See Notes 2 and 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.

Southern Company Gas owns a 50% interest in a LNG liquefaction and storage facility in Jacksonville, Florida, which was placed in service in October 2018. The facility, outfitted with a 2.0 million gallon storage tank with the capacity to produce in excess of 120,000 gallons of LNG per day, is not expected to have a material impact on Southern Company Gas' 2019 financial statements.

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, 2018, the facility's property, plant, and equipment had a net book value of $109 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, 2018. 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 Southern Company Gas' financial statements.

Effective January 1, 2018, Southern Company Gas 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, Southern Company Gas accrued $21 million as of January 1, 2018, of which $9 million was recorded as regulatory assets by the natural gas distribution utilities. See Note 2 to the financial statements under "Southern Company Gas" for additional information.

ACCOUNTING POLICIES

Application of Critical Accounting Policies and Estimates

Southern Company Gas prepares its financial statements in accordance with GAAP. Significant accounting policies are described in Notes 1, 5, and 6 to the financial statements. In the application of these policies, certain estimates are made that may have a material impact on Southern Company Gas' 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 Southern Company Gas' total operating revenues for 2018 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 Southern Company Gas' 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 Southern Company Gas' results of operations and financial condition than they would on a non-regulated company.

As reflected in Note 2 to the financial statements under "Southern Company Gas – Regulatory Assets and Liabilities," 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 Southern Company Gas' 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 Southern Company Gas operates.

On behalf of Southern Company Gas, 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 Southern Company Gas', 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 Southern Company Gas' financial statements.

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

Assessment of Assets

Goodwill

Southern Company Gas 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 Southern Company Gas' impairment test, Southern Company Gas may perform an initial qualitative 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 quantitative goodwill impairment test. If Southern Company Gas 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 Southern Company Gas 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 compares the fair value of the reporting unit to its carrying value to determine if the fair value is greater than its carrying value. Under ASU No. 2017-04, which was adopted effective January 1, 2018, any goodwill impairment loss will be measured as the excess of a reporting unit's carrying amount over its fair value.

For the 2018 and 2016 annual impairment tests, Southern Company Gas performed the qualitative 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. For the 2017 annual impairment test, Southern Company Gas performed the quantitative assessment, which resulted in the fair value of all of its reporting units that have goodwill exceeding their carrying value. In the first quarter 2018, Southern Company Gas recorded a $42 million impairment charge in contemplation of the sale of Pivotal Home Solutions.

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 Gas considers these estimates to be critical accounting estimates.

See Note 1 to the financial statements under "Recently Adopted Accounting Standards – Other" for information on Southern Company Gas' adoption of ASU No. 2017-04.

Long-Lived Assets

Southern Company Gas depreciates or amortizes its long-lived and intangible assets over their estimated useful lives. Southern Company Gas 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, Southern Company Gas

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, Southern Company Gas 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, Southern Company Gas considers these estimates to be critical accounting estimates.

See Notes 2 and 3 to the financial statements under "FERC Matters – Southern Company Gas" and "Other Matters – Southern Company Gas," respectively, for information on certain assets recently evaluated for impairment.

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 complex. The treatment of a single contract may vary from period to period depending upon accounting elections, changes in Southern Company Gas' 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. Southern Company Gas 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 utilizes 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. Prior to its disposition, Elizabethtown Gas utilized the same policy.

Southern Company Gas 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 Southern Company Gas 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 Southern Company Gas 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 Southern Company Gas' 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.

Southern Company Gas 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 Gas' nonperformance risk on its liabilities.

If there is a significant change in the underlying market prices or pricing assumptions Southern Company Gas uses in pricing its derivative assets or liabilities, Southern Company Gas may experience a significant impact on its financial position, results of operations, and cash flows. See Note 14 to the financial statements for additional information.

Given the assumptions used in pricing the derivative asset or liability, Southern Company Gas 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

Southern Company Gas' 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 Southern Company Gas believes that the assumptions used are appropriate, differences in actual experience or significant changes in assumptions would affect its pension and other postretirement benefit costs and obligations.

Key elements in determining Southern Company Gas' 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 Southern Company Gas' liability related to the pension and other postretirement benefit plans, Southern 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.

A 25 basis point change in any significant assumption (discount rate, salary increases, or long-term rate of return on plan assets) would result in a $3 million or less change in total annual benefit expense, a $30 million or less change in the projected obligation for the pension plan, and a $6 million or less change in the projected obligation for other post retirement benefit plans.

See Note 11 to the financial statements for additional information regarding pension and other postretirement benefits.

Contingent Obligations

Southern Company Gas 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 Notes 2 and 3 to the financial statements for more information regarding certain of these contingencies. Southern Company Gas 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 Southern Company Gas' results of operations, cash flows, or financial condition.

Recently Issued Accounting Standards

See Note 1 to the financial statements under "Recently Adopted Accounting Standards" for additional information.

In 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 Southern Company Gas adopted the new standard effective January 1, 2019.

Southern Company Gas elected the transition methodology provided by ASU No. 2018-11, *Leases (Topic 842): Targeted Improvements*, whereby the requirements of ASU 2016-02 are applied on a prospective basis as of the adoption date of January 1, 2019, without restating prior periods. Southern Company Gas elected the package of practical expedients provided by ASU 2016-02 that allows prior determinations of whether existing contracts are, or contain, leases and the classification of existing leases to continue without reassessment. Additionally, Southern Company Gas applied the use-of-hindsight practical expedient in determining lease terms as of the date of adoption and elected the practical expedient that allows existing land easements not previously accounted for as leases not to be reassessed. Southern Company Gas also made accounting policy elections to account

for short-term leases in all asset classes as off-balance sheet leases and combined lease and non-lease components in the computations of lease obligations and right-of-use assets for most asset classes.

Southern Company Gas completed the implementation of a new application to track and account for its leases and updated its internal controls and accounting policies to support the accounting for leases under ASU 2016-02. Southern Company Gas completed its lease inventory and determined its most significant leases involve real estate and fleet vehicles. In the first quarter 2019, the adoption of ASU 2016-02 resulted in recording lease liabilities and right-of-use assets on Southern Company Gas' balance sheet each totaling $86 million, with no impact on Southern Company Gas' statement of income.

FINANCIAL CONDITION AND LIQUIDITY

Overview

Southern Company Gas' financial condition remained stable at December 31, 2018. Southern Company Gas' cash requirements primarily consist of funding ongoing operations, common stock dividends, capital expenditures, investments in unconsolidated subsidiaries, 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 Southern Company Gas' cash needs. For the three-year period from 2019 through 2021, Southern Company Gas' projected common stock dividends, capital expenditures, and debt maturities are expected to exceed operating cash flows. Southern Company Gas 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. Southern Company Gas plans to use commercial paper to manage seasonal variations in operating cash flows and other working capital needs. Southern Company Gas 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. At December 31, 2018, the amount of subsidiary retained earnings restricted to dividend totaled $814 million. This restriction did not impact Southern Company Gas' ability to meet its cash obligations, nor does management expect such restriction to materially impact Southern Company Gas' ability to meet its currently anticipated cash obligations.

Southern Company Gas' investments in the qualified pension plan decreased in value at December 31, 2018 as compared to December 31, 2017. There were no voluntary contributions to the qualified pension plan in 2018 and no mandatory contributions to its qualified pension plan are anticipated during 2019. See Note 11 to the financial statements for additional information.

Net cash provided from operating activities in the successor year ended 2018 totaled $764 million, a decrease of $117 million from 2017. The decrease was primarily due to higher income tax payments as a result of net taxable gains from the Southern Company Gas Dispositions, partially offset by increased volumes of natural gas sold during 2018 as a result of colder weather compared to 2017. Net cash provided from operating activities totaled $881 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 $327 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, Southern Company Gas 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 investing activities for the successor year ended 2018 totaled $1.0 billion and was primarily due to the $2.6 billion proceeds from the Southern Company Gas Dispositions, partially offset by gross property additions primarily related to utility capital expenditures and pre-approved rider and infrastructure investments recovered through replacement programs at gas distribution operations as well as capital contributed to equity method pipeline investments partially offset by capital returned from equity method pipeline investments. Net cash used for investing activities totaled $1.6 billion for the successor year ended 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 pipeline investments, partially offset by $80 million in capital returned from equity method pipeline investments. 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 Southern Company Gas' acquisition of the 50% interest in SNG, and $632 million in capital expenditures. Net cash used for investing activities was $556 million for the predecessor period of January 1, 2016 through June 30, 2016 which primarily related to capital expenditures. See Note 7 to the financial statements under "Southern Company Gas" and Note 15 to the financial statements under "Southern Company Gas – Investment in SNG" for additional information.

Net cash used for financing activities for the successor year ended 2018 of $1.8 billion included payments of common stock dividends to Southern Company, return of capital to Southern Company, redemptions of gas facility revenue bonds and senior notes, and repayments of commercial paper borrowings and long-term debt, partially offset by debt issuances and capital contributions from Southern Company. 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 Southern Company Gas' 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. See Note 7 to the financial statements under "Southern Company Gas" and Note 15 to the financial statements under "Southern Company Gas – Investment in SNG" for additional information.

Significant balance sheet changes at December 31, 2018 include $2.8 billion and $403 million in total assets and liabilities sold, respectively, associated with the Southern Company Gas Dispositions as described in Note 15 to the financial statements herein under "Southern Company Gas." After adjusting for these changes, other significant balance sheet changes included an increase of $1.0 billion in total property, plant, and equipment primarily due to capital expenditures for infrastructure replacement programs, a decrease of $73 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 impacts of State of Illinois tax legislation, and a decrease of $108 million in long-term debt (including securities due within one year), primarily due to $200 million redemption of gas facility revenue bonds and $155 million in repayments of long-term debt, partially offset by the issuance of $300 million of first mortgage bonds at Nicor Gas. Other significant balance sheet changes include a decrease of $868 million in notes payable primarily related to a decrease in commercial paper borrowings of $840 million at Southern Company Gas Capital and $28 million at Nicor Gas. See FUTURE EARNINGS POTENTIAL – "Income Tax Matters" and FINANCIAL CONDITION AND LIQUIDITY – "Financing Activities" herein and Notes 8 and 10 to the financial statements for additional information.

Sources of Capital

Southern Company Gas 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 securities issuances, borrowings from financial institutions, and equity contributions from Southern Company. However, the amount, type, and timing of any future financings, if needed, depend upon prevailing market conditions, regulatory approval, and other factors. With respect to the public offering of securities, Southern Company Gas (excluding its subsidiaries) and Southern Company Gas Capital file registration statements with the SEC under the Securities Act of 1933, as amended. The issuance of securities by Nicor Gas is generally subject to the approval of the Illinois Commission.

Southern Company Gas obtains separate financing without credit support from any affiliate in the Southern Company system. See Note 8 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, except as described below, funds of Southern Company Gas are not commingled with funds of any other company in the Southern Company system.

Southern Company Gas 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 Southern Company Gas' other subsidiaries benefit from Southern Company Gas Capital's commercial paper program.

At December 31, 2018, Southern Company Gas' current liabilities exceeded current assets by $469 million, primarily as a result of $650 million in notes payable and $357 million of securities due within one year. Southern Company Gas' 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.

At December 31, 2018, Southern Company Gas had $64 million of cash and cash equivalents. Committed credit arrangements with banks at December 31, 2018 were as follows:

Company	Expires 2022	Unused
	(millions)	
Southern Company Gas Capital[(a)]	$ 1,400	$ 1,395
Nicor Gas	500	500
Total[(b)]	$ 1,900	$ 1,895

(a) Southern Company Gas guarantees the obligations of Southern Company Gas Capital.
(b) Pursuant to the credit arrangement, the allocations between Southern Company Gas Capital and Nicor Gas may be adjusted.

See Note 8 to the financial statements under "Bank Credit Arrangements" for additional information.

The multi-year credit arrangement of Southern Company Gas Capital and Nicor Gas (Facility) contains a covenant that limits the debt levels 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 Southern Company Gas or Nicor Gas defaulted on indebtedness, the payment of which was then accelerated. At December 31, 2018, 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 Southern Company Gas.

Southern Company Gas has substantial cash flow from operating activities and access to capital markets, including the commercial paper programs, and financial institutions to meet liquidity needs. Southern Company Gas makes short-term borrowings primarily through commercial paper programs that have the liquidity support of the committed bank credit arrangements described above. Short-term borrowings are included in notes payable in the balance sheets.

Details of short-term borrowings were as follows:

	Short-term Debt at the End of the Period		Short-term Debt During the Period(*)		
	Amount Outstanding	Weighted Average Interest Rate	Average Amount Outstanding	Weighted Average Interest Rate	Maximum Amount Outstanding
	(in millions)		*(in millions)*		*(in millions)*
Successor – December 31, 2018:					
Commercial paper:					
Southern Company Gas Capital	**$ 403**	**3.05%**	**$ 489**	**2.25%**	**$ 1,261**
Nicor Gas	**247**	**2.98%**	**123**	**2.16%**	**275**
Short-term bank debt:					
Southern Company Gas Capital	**—**	**—%**	**31**	**2.72%**	**276**
Total	**$ 650**	**3.03%**	**$ 643**	**2.25%**	
Successor – December 31, 2017:					
Commercial paper:					
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:					
Commercial paper:					
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 %	

(*) Average and maximum amounts are based upon daily balances during the 12-month periods.

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

Financing Activities

The long-term debt on Southern Company Gas' balance sheets includes both principal and non-principal components. At December 31, 2018, the non-principal components totaled $456 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, Southern Company Gas 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 Southern Company Gas 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.

Except as otherwise described herein, Southern Company Gas and its subsidiaries used the proceeds of debt issuances for their redemptions and maturities, to pay common stock dividends, to repay short-term indebtedness, for capital expenditures, and for general corporate purposes, including working capital.

In January 2018, Southern Company Gas issued a floating rate promissory note to Southern Company in an aggregate principal amount of $100 million bearing interest based on one-month LIBOR. In March 2018, Southern Company Gas repaid this promissory note.

Prior to its sale, in the second quarter 2018, Pivotal Utility Holdings caused $200 million aggregate principal amount of gas facility revenue bonds to be redeemed. Also in the second quarter 2018, Pivotal Utility Holdings, as borrower, and Southern Company Gas, as guarantor, entered into a $181 million short-term delayed draw floating rate bank term loan bearing interest

based on one-month LIBOR, which Pivotal Utility Holdings used to repay the gas facility revenue bonds. In July 2018, Pivotal Utility Holdings repaid this short-term loan.

In May 2018, Southern Company Gas Capital borrowed $95 million pursuant to a short-term uncommitted bank credit arrangement, guaranteed by Southern Company Gas, bearing interest at a rate agreed upon by Southern Company Gas Capital and the bank from time to time and payable on no less than 30 days' demand by the bank. In July 2018, Southern Company Gas Capital repaid this loan.

Nicor Gas issued $300 million aggregate principal amount of first mortgage bonds in a private placement, of which $100 million was issued in August 2018 and $200 million was issued in November 2018.

In October 2018, Southern Company Gas Capital repaid at maturity $155 million aggregate principal amount of 3.50% Series B Senior Notes.

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

Southern Company Gas 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, 2018 was $30 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 Gas to access capital markets and would be likely to impact the cost at which it does so.

On September 28, 2018, Fitch assigned a negative rating outlook to the ratings of Southern Company and certain of its subsidiaries (including Southern Company Gas, Southern Company Gas Capital, and Nicor Gas).

As a result of 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 Southern Company Gas, may be negatively impacted. Southern Company Gas and its regulated subsidiaries have taken actions to mitigate the resulting impacts, which, among other alternatives, include adjusting capital structure. Absent actions by Southern Company and its subsidiaries that fully mitigate the impacts, Southern Company Gas', Southern Company Gas Capital's, and Nicor Gas' credit ratings could be negatively affected. The Georgia PSC's May 15, 2018 approval of a stipulation for Atlanta Gas Light's annual rate adjustment maintained the previously authorized earnings band and increased the equity ratio to address the negative cash flow and credit metric impacts of the Tax Reform Legislation. See Note 2 to the financial statements under "Southern Company Gas" for information on additional rate proceedings for Nicor Gas and Atlanta Gas Light expected to conclude in 2019.

Market Price Risk

Southern Company Gas 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 Southern Company Gas 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, Southern Company Gas nets the exposures, where possible, to take advantage of natural offsets and enters into various derivative transactions for the remaining exposures pursuant to Southern Company Gas' policies in areas such as counterparty exposure and risk management practices. Southern Company Gas 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.

Certain natural gas distribution utilities of Southern Company Gas 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, Southern Company Gas 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 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 may not be designated, for hedge accounting treatment. Southern Company Gas had no material change in market risk exposure for the year ended December 31, 2018 when compared to the year ended December 31, 2017.

For the periods presented below, the changes in net fair value of derivative contracts were as follows:

	Successor			Predecessor
	Year Ended December 31, 2018	Year Ended December 31, 2017	July 1, 2016 through December 31, 2016	January 1, 2016 through June 30, 2016
		(in millions)		*(in millions)*
Contracts outstanding at beginning of period, assets (liabilities), net	**$ (106)**	$ 8	$ (54)	$ 75
Contracts realized or otherwise settled	**66**	(1)	18	(77)
Current period changes[a]	**(127)**	(113)	48	(82)
Contracts outstanding at end of period, assets (liabilities), net	**(167)**	(106)	12	(84)
Netting of cash collateral	**277**	193	62	120
Cash collateral and net fair value of contracts outstanding at end of period[b]	**$ 110**	$ 87	$ 74	$ 36

(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 $8 million and $11 million at December 31, 2018 and 2017, respectively, and includes premium and intrinsic value associated with weather derivatives of $4 million at December 31, 2016, and $5 million at June 30, 2016.

The net hedge volume of energy-related derivative contracts for natural gas positions at December 31, 2018 and 2017 were as follows:

	2018	2017
	mmBtu Volume	
	(in millions)	
Commodity – Natural gas	**120**	300
Net Purchased / (Sold) Volume	**120**	300

Southern Company Gas' 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 4.16 billion mmBtu and short natural gas positions of 4.04 billion mmBtu at December 31, 2018 and 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.

Energy-related derivative contracts that are designated as regulatory hedges relate primarily to Southern Company Gas' 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.

Southern Company Gas 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 13 to the financial statements for further discussion of fair value measurements.

The maturities of the energy-related derivative contracts at December 31, 2018 were as follows:

		Fair Value Measurements December 31, 2018		
		Maturity		
	Total Fair Value	Year 1	Years 2 & 3	Years 4 & 5
		(in millions)		
Level 1[(a)]	**$ (179)**	**$ (59)**	**$ (86)**	**$ (34)**
Level 2[(b)]	**12**	**37**	**—**	**(25)**
Fair value of contracts outstanding at end of period[(c)]	**$ (167)**	**$ (22)**	**$ (86)**	**$ (59)**

(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 $277 million as well as premium and associated intrinsic value associated with weather derivatives of $8 million at December 31, 2018.

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. Southern Company Gas' VaR may not be comparable to that of other companies due to differences in the factors used to calculate VaR. Southern Company Gas' 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 Southern Company Gas is managed in accordance with established policies that limit market risk and require daily reporting of potential financial exposure to senior management. Because Southern Company Gas generally manages physical gas assets and economically protects its positions by hedging in the futures markets, Southern Company Gas' open exposure is generally mitigated. Southern Company Gas employs daily risk testing, using both VaR and stress testing, to evaluate the risk of its positions.

Southern Company Gas 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.

For the periods presented below, wholesale gas services had the following VaRs:

	Successor			Predecessor
	Year Ended December 31, 2018	Year Ended December 31, 2017	July 1, 2016 through December 31, 2016	January 1, 2016 through June 30, 2016
	(in millions)			*(in millions)*
Period end[(*)]	**$ 6.4**	$ 4.8	$ 2.3	$ 1.9
Average	**3.7**	2.0	2.0	2.0
High[(*)]	**11.7**	4.8	2.8	2.5
Low	**1.2**	1.0	1.4	1.6

(*) Increases in VaR at December 31, 2018 and 2017 were driven by significant natural gas price increases in Sequent's key markets. The natural gas price increase in 2018 was driven by an industry-wide lower-than-normal natural gas storage inventory position and colder-than-normal weather in the middle of fourth quarter 2018. The natural gas price increase in 2017 was driven by colder-than-normal weather. As weather and natural gas prices moderated subsequent to December 31, 2018 and 2017, VaR reduced to a level consistent with December 31, 2016.

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 2018, the four largest Marketers based on customer count, which includes SouthStar, accounted for 20% of Southern Company Gas' adjusted operating margin and 25% of gas distribution operations' adjusted operating margin.

Several factors are designed to mitigate Southern Company Gas' 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, a management risk oversight committee reviews the adequacy of credit support coverage, credit rating profiles of credit support providers, and payment status of each Marketer. Southern Company Gas 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.

Wholesale Gas Services

Southern Company Gas has established credit policies to determine and monitor the creditworthiness of counterparties, as well as the quality of pledged collateral. Southern Company Gas also utilizes netting agreements whenever possible to mitigate exposure to counterparty credit risk. When Southern Company Gas is engaged in more than one outstanding derivative transaction with the same counterparty and 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. 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 netting and cash collateral agreements include such provisions.

Southern Company Gas may require counterparties to pledge additional collateral when deemed necessary. Southern Company Gas 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, 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.

Certain of Southern Company Gas' 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, 2018, for agreements with such features, Southern Company Gas' derivative instruments with liability fair values totaled $5 million for which Southern Company Gas had no collateral posted with derivatives counterparties to satisfy these arrangements.

Southern Company Gas has a concentration of credit risk as measured by its 30-day receivable exposure plus forward exposure. At December 31, 2018, wholesale gas services' top 20 counterparties represented approximately 48%, or $298 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 a S&P equivalent.

The following table provides credit risk information related to Southern Company Gas' third-party natural gas contracts receivable and payable positions at December 31:

	Gross Receivables		Gross Payables	
	2018	2017	**2018**	2017
	(in millions)		*(in millions)*	
Netting agreements in place:				
Counterparty is investment grade	**$ 461**	$ 342	**$ 255**	$ 202
Counterparty is non-investment grade	**5**	20	**95**	25
Counterparty has no external rating	**314**	226	**505**	315
No netting agreements in place:				
Counterparty is investment grade	**19**	19	**1**	4
Counterparty has no external rating	**2**	—	**—**	—
Amount recorded in balance sheets	**$ 801**	$ 607	**$ 856**	$ 546

Gas Marketing Services

Southern Company Gas 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 Southern Company Gas' credit threshold. Southern Company Gas 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, Southern Company Gas 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.

Capital Requirements and Contractual Obligations

Southern Company Gas' capital investments are currently estimated to total $1.6 billion for 2019, $1.9 billion for 2020, $1.3 billion for 2021, $1.2 billion for 2022, and $1.3 billion for 2023. 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 11 to the financial statements, Southern Company Gas provides postretirement benefits to certain eligible employees and funds trusts to the extent required by the applicable state regulatory agencies.

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 1, 3, 8, 9, 11, and 14 to the financial statements for additional information.

Contractual Obligations

Contractual obligations at December 31, 2018 were as follows:

	2019	2020-2021	2022-2023	After 2023	Total
			(in millions)		
Long-term debt[(a)] —					
Principal	$ 350	$ 330	$ 446	$ 4,359	$ 5,485
Interest	244	453	422	3,242	4,361
Pipeline charges, storage capacity, and gas supply[(b)]	781	1,104	901	1,871	4,657
Operating leases[(c)]	18	31	23	34	106
Asset management agreements[(d)]	10	8	—	—	18
Financial derivative obligations[(e)]	583	217	109	—	909
Pension and other postretirement benefit plans[(f)]	16	32	—	—	48
Purchase commitments —					
Capital[(g)]	1,591	3,231	2,496	—	7,318
Other[(h)]	25	4	2	—	31
Total	$ 3,618	$ 5,410	$ 4,399	$ 9,506	$ 22,933

(a) Amounts are reflected based on final maturity dates. Southern Company Gas 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, 2018, 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 47 million mmBtu at floating gas prices calculated using forward natural gas prices at December 31, 2018 and valued at $150 million. Southern Company Gas 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, Southern Company Gas' 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 14 to the financial statements for additional information.

(f) Southern Company Gas forecasts contributions to the pension and other postretirement benefit plans over a three-year period. Southern Company Gas 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 Southern Company Gas' corporate assets. See Note 11 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 Southern Company Gas' corporate assets.

(g) Estimated capital expenditures are provided through 2023. At December 31, 2018, significant purchase commitments were outstanding in connection with infrastructure and other construction programs.

(h) Includes contractual environmental remediation liabilities that are generally recoverable through base rates or rate rider mechanisms and LTSAs.

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 to the financial statements under "Financial Instruments" in Item 8 herein. Also see Notes 13 and 14 to the financial statements in Item 8 herein.

Item 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA

INDEX TO 2018 FINANCIAL STATEMENTS

	Page
The Southern Company and Subsidiary Companies:	
Report of Independent Registered Public Accounting Firm	II-216
Consolidated Statements of Income for the Years Ended December 31, 2018, 2017, and 2016	II-217
Consolidated Statements of Comprehensive Income for the Years Ended December 31, 2018, 2017, and 2016	II-218
Consolidated Statements of Cash Flows for the Years Ended December 31, 2018, 2017, and 2016	II-219
Consolidated Balance Sheets at December 31, 2018 and 2017	II-220
Consolidated Statements of Capitalization at December 31, 2018 and 2017	II-222
Consolidated Statements of Stockholders' Equity for the Years Ended December 31, 2018, 2017, and 2016	II-224
Alabama Power:	
Report of Independent Registered Public Accounting Firm	II-225
Statements of Income for the Years Ended December 31, 2018, 2017, and 2016	II-226
Statements of Comprehensive Income for the Years Ended December 31, 2018, 2017, and 2016	II-227
Statements of Cash Flows for the Years Ended December 31, 2018, 2017, and 2016	II-228
Balance Sheets at December 31, 2018 and 2017	II-229
Statements of Capitalization at December 31, 2018 and 2017	II-231
Statements of Common Stockholder's Equity for the Years Ended December 31, 2018, 2017, and 2016	II-232
Georgia Power:	
Report of Independent Registered Public Accounting Firm	II-233
Statements of Income for the Years Ended December 31, 2018, 2017, and 2016	II-234
Statements of Comprehensive Income for the Years Ended December 31, 2018, 2017, and 2016	II-235
Statements of Cash Flows for the Years Ended December 31, 2018, 2017, and 2016	II-236
Balance Sheets at December 31, 2018 and 2017	II-237
Statements of Capitalization at December 31, 2018 and 2017	II-239
Statements of Common Stockholder's Equity for the Years Ended December 31, 2018, 2017, and 2016	II-240
Mississippi Power:	
Report of Independent Registered Public Accounting Firm	II-241
Statements of Operations for the Years Ended December 31, 2018, 2017, and 2016	II-242
Statements of Comprehensive Income (Loss) for the Years Ended December 31, 2018, 2017, and 2016	II-243
Statements of Cash Flows for the Years Ended December 31, 2018, 2017, and 2016	II-244
Balance Sheets at December 31, 2018 and 2017	II-245
Statements of Capitalization at December 31, 2018 and 2017	II-247
Statements of Common Stockholder's Equity for the Years Ended December 31, 2018, 2017, and 2016	II-248

	Page
Southern Power and Subsidiary Companies:	
Report of Independent Registered Public Accounting Firm	II-249
Consolidated Statements of Income for the Years Ended December 31, 2018, 2017, and 2016	II-250
Consolidated Statements of Comprehensive Income for the Years Ended December 31, 2018, 2017, and 2016	II-251
Consolidated Statements of Cash Flows for the Years Ended December 31, 2018, 2017, and 2016	II-252
Consolidated Balance Sheets at December 31, 2018 and 2017	II-253
Consolidated Statements of Stockholders' Equity for the Years Ended December 31, 2018, 2017, and 2016	II-255
Southern Company Gas and Subsidiary Companies:	
Report of Independent Registered Public Accounting Firm	II-256
Consolidated Statements of Income for the Years Ended December 31, 2018, 2017, and 2016	II-257
Consolidated Statements of Comprehensive Income for the Years Ended December 31, 2018, 2017, and 2016	II-258
Consolidated Statements of Cash Flows for the Years Ended December 31, 2018, 2017, and 2016	II-259
Consolidated Balance Sheets at December 31, 2018 and 2017	II-260
Consolidated Statements of Capitalization at December 31, 2018 and 2017	II-262
Consolidated Statements of Stockholders' Equity for the Years Ended December 31, 2018, 2017, and 2016	II-263
Combined Notes to Financial Statements	II-264

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 (Southern Company) as of December 31, 2018 and 2017, 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, 2018, and the related notes (collectively referred to as the "financial statements"). We also have audited Southern Company's internal control over financial reporting as of December 31, 2018, 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 referred to above present fairly, in all material respects, the financial position of Southern Company as of December 31, 2018 and 2017, and the results of its operations and its cash flows for each of the three years in the period ended December 31, 2018, in conformity with accounting principles generally accepted in the United States of America. Also, in our opinion, Southern Company maintained, in all material respects, effective internal control over financial reporting as of December 31, 2018, based on criteria established in *Internal Control – Integrated Framework (2013)* issued by COSO.

Basis for Opinions

Southern 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. Our responsibility is to express an opinion on these financial statements and an opinion on Southern 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 Southern 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 19, 2019

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

CONSOLIDATED STATEMENTS OF INCOME
For the Years Ended December 31, 2018, 2017, and 2016
Southern Company and Subsidiary Companies 2018 Annual Report

	2018	2017	2016
		(in millions)	
Operating Revenues:			
Retail electric revenues	**$ 15,222**	$ 15,330	$ 15,234
Wholesale electric revenues	**2,516**	2,426	1,926
Other electric revenues	**664**	681	698
Natural gas revenues	**3,854**	3,791	1,596
Other revenues	**1,239**	803	442
Total operating revenues	**23,495**	23,031	19,896
Operating Expenses:			
Fuel	**4,637**	4,400	4,361
Purchased power	**971**	863	750
Cost of natural gas	**1,539**	1,601	613
Cost of other sales	**806**	513	260
Other operations and maintenance	**5,889**	5,739	5,382
Depreciation and amortization	**3,131**	3,010	2,502
Taxes other than income taxes	**1,315**	1,250	1,113
Estimated loss on plants under construction	**1,097**	3,362	428
Impairment charges	**210**	—	—
Gain on dispositions, net	**(291)**	(40)	1
Total operating expenses	**19,304**	20,698	15,410
Operating Income	**4,191**	2,333	4,486
Other Income and (Expense):			
Allowance for equity funds used during construction	**138**	160	202
Earnings from equity method investments	**148**	106	59
Interest expense, net of amounts capitalized	**(1,842)**	(1,694)	(1,317)
Other income (expense), net	**114**	163	50
Total other income and (expense)	**(1,442)**	(1,265)	(1,006)
Earnings Before Income Taxes	**2,749**	1,068	3,480
Income taxes	**449**	142	951
Consolidated Net Income	**2,300**	926	2,529
Dividends on preferred and preference stock of subsidiaries	**16**	38	45
Net income attributable to noncontrolling interests	**58**	46	36
Consolidated Net Income Attributable to Southern Company	**$ 2,226**	$ 842	$ 2,448
Common Stock Data:			
Earnings per share —			
Basic	**$ 2.18**	$ 0.84	$ 2.57
Diluted	**2.17**	0.84	2.55
Average number of shares of common stock outstanding — (in millions)			
Basic	**1,020**	1,000	951
Diluted	**1,025**	1,008	958

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

CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME
For the Years Ended December 31, 2018, 2017, and 2016
Southern Company and Subsidiary Companies 2018 Annual Report

	2018	2017	2016
		(in millions)	
Consolidated Net Income	**$ 2,300**	$ 926	$ 2,529
Other comprehensive income (loss):			
Qualifying hedges:			
Changes in fair value, net of tax of $(16), $34, and $(84), respectively	**(47)**	57	(136)
Reclassification adjustment for amounts included in net income, net of tax of $24, $(37), and $43, respectively	**72**	(60)	69
Pension and other postretirement benefit plans:			
Benefit plan net gain (loss), net of tax of $(2), $6, and $10, respectively	**(5)**	17	13
Reclassification adjustment for amounts included in net income, net of tax of $5, $(6), and $3, respectively	**6**	(23)	4
Total other comprehensive income (loss)	**26**	(9)	(50)
Dividends on preferred and preference stock of subsidiaries	**16**	38	45
Comprehensive income attributable to noncontrolling interests	**58**	46	36
Consolidated Comprehensive Income Attributable to Southern Company	**$ 2,252**	$ 833	$ 2,398

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

CONSOLIDATED STATEMENTS OF CASH FLOWS
For the Years Ended December 31, 2018, 2017, and 2016
Southern Company and Subsidiary Companies 2018 Annual Report

	2018	2017	2016
		(in millions)	
Operating Activities:			
Consolidated net income	**$ 2,300**	$ 926	$ 2,529
Adjustments to reconcile consolidated net income to net cash provided from operating activities —			
Depreciation and amortization, total	**3,549**	3,457	2,923
Deferred income taxes	**94**	166	(127)
Collateral deposits	**17**	(4)	(102)
Allowance for equity funds used during construction	**(138)**	(160)	(202)
Pension and postretirement funding	**(4)**	(2)	(1,029)
Settlement of asset retirement obligations	**(244)**	(177)	(171)
Stock based compensation expense	**125**	109	121
Hedge settlements	**(10)**	6	(233)
Estimated loss on plants under construction	**1,093**	3,179	428
Impairment charges	**210**	—	—
Gain on dispositions, net	**(301)**	(42)	(2)
Other, net	**(22)**	(112)	(219)
Changes in certain current assets and liabilities —			
-Receivables	**(426)**	(202)	(544)
-Fossil fuel for generation	**123**	36	178
-Natural gas for sale	**49**	36	(226)
-Other current assets	**(127)**	(143)	(206)
-Accounts payable	**291**	(280)	301
-Accrued taxes	**267**	(142)	1,456
-Retail fuel cost over recovery	**36**	(212)	(231)
-Other current liabilities	**63**	(45)	250
Net cash provided from operating activities	**6,945**	6,394	4,894
Investing Activities:			
Business acquisitions, net of cash acquired	**(65)**	(1,054)	(10,680)
Property additions	**(8,001)**	(7,423)	(7,310)
Proceeds pursuant to the Toshiba Guarantee, net of joint owner portion	**—**	1,682	—
Nuclear decommissioning trust fund purchases	**(1,117)**	(811)	(1,160)
Nuclear decommissioning trust fund sales	**1,111**	805	1,154
Proceeds from dispositions	**2,956**	97	15
Cost of removal, net of salvage	**(388)**	(313)	(245)
Change in construction payables, net	**50**	259	(121)
Investment in unconsolidated subsidiaries	**(114)**	(152)	(1,444)
Payments pursuant to LTSAs	**(186)**	(227)	(134)
Other investing activities	**(6)**	(53)	(122)
Net cash used for investing activities	**(5,760)**	(7,190)	(20,047)
Financing Activities:			
Increase (decrease) in notes payable, net	**(774)**	(401)	1,228
Proceeds —			
Long-term debt	**2,478**	5,858	16,368
Common stock	**1,090**	793	3,758
Preferred stock	**—**	250	—
Short-term borrowings	**3,150**	1,259	—
Redemptions and repurchases —			
Long-term debt	**(5,533)**	(2,930)	(3,145)
Preferred and preference stock	**(33)**	(658)	—
Short-term borrowings	**(1,900)**	(659)	(478)
Distributions to noncontrolling interests	**(153)**	(119)	(72)
Capital contributions from noncontrolling interests	**2,551**	80	682
Payment of common stock dividends	**(2,425)**	(2,300)	(2,104)
Other financing activities	**(264)**	(222)	(512)
Net cash provided from (used for) financing activities	**(1,813)**	951	15,725
Net Change in Cash, Cash Equivalents, and Restricted Cash	**(628)**	155	572
Cash, Cash Equivalents, and Restricted Cash at Beginning of Year	**2,147**	1,992	1,420
Cash, Cash Equivalents, and Restricted Cash at End of Year	**$ 1,519**	$ 2,147	$ 1,992
Supplemental Cash Flow Information:			
Cash paid (received) during the period for —			
Interest (net of $72, $89, and $128 capitalized, respectively)	**$ 1,794**	$ 1,676	$ 1,066
Income taxes (net of refunds)	**172**	(410)	(148)
Noncash transactions — Accrued property additions at year-end	**1,103**	985	1,262

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

CONSOLIDATED BALANCE SHEETS
At December 31, 2018 and 2017
Southern Company and Subsidiary Companies 2018 Annual Report

Assets	2018	2017
		(in millions)
Current Assets:		
Cash and cash equivalents	**$ 1,396**	$ 2,130
Receivables —		
Customer accounts receivable	**1,726**	1,806
Energy marketing receivable	**801**	607
Unbilled revenues	**654**	810
Under recovered fuel clause revenues	**115**	171
Other accounts and notes receivable	**813**	698
Accumulated provision for uncollectible accounts	**(50)**	(44)
Materials and supplies	**1,465**	1,438
Fossil fuel for generation	**405**	594
Natural gas for sale	**524**	595
Prepaid expenses	**432**	452
Assets from risk management activities, net of collateral	**222**	137
Other regulatory assets, current	**525**	604
Assets held for sale, current	**393**	12
Other current assets	**162**	62
Total current assets	**9,583**	10,072
Property, Plant, and Equipment:		
In service	**103,706**	103,542
Less: Accumulated depreciation	**31,038**	31,457
Plant in service, net of depreciation	**72,668**	72,085
Nuclear fuel, at amortized cost	**875**	883
Construction work in progress	**7,254**	6,904
Total property, plant, and equipment	**80,797**	79,872
Other Property and Investments:		
Goodwill	**5,315**	6,268
Equity investments in unconsolidated subsidiaries	**1,580**	1,513
Other intangible assets, net of amortization of $235 and $186 at December 31, 2018 and December 31, 2017, respectively	**613**	873
Nuclear decommissioning trusts, at fair value	**1,721**	1,832
Leveraged leases	**798**	775
Miscellaneous property and investments	**269**	249
Total other property and investments	**10,296**	11,510
Deferred Charges and Other Assets:		
Deferred charges related to income taxes	**794**	825
Unamortized loss on reacquired debt	**323**	206
Other regulatory assets	**8,308**	6,943
Assets held for sale	**5,350**	—
Other deferred charges and assets	**1,463**	1,577
Total deferred charges and other assets	**16,238**	9,551
Total Assets	**$ 116,914**	$ 111,005

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

CONSOLIDATED BALANCE SHEETS
At December 31, 2018 and 2017
Southern Company and Subsidiary Companies 2018 Annual Report

Liabilities and Stockholders' Equity	**2018**	2017
	(in millions)	
Current Liabilities:		
Securities due within one year	**$ 3,198**	$ 3,892
Notes payable	**2,915**	2,439
Energy marketing trade payables	**856**	546
Accounts payable	**2,580**	2,530
Customer deposits	**522**	542
Accrued taxes	**656**	636
Accrued interest	**472**	488
Accrued compensation	**1,030**	959
Asset retirement obligations, current	**404**	351
Other regulatory liabilities, current	**376**	337
Liabilities held for sale, current	**425**	—
Other current liabilities	**852**	874
Total current liabilities	**14,286**	13,594
Long-Term Debt (See accompanying statements)	**40,736**	44,462
Deferred Credits and Other Liabilities:		
Accumulated deferred income taxes	**6,558**	6,842
Deferred credits related to income taxes	**6,460**	7,256
Accumulated deferred ITCs	**2,372**	2,267
Employee benefit obligations	**2,147**	2,256
Asset retirement obligations	**8,990**	4,473
Accrued environmental remediation	**268**	389
Other cost of removal obligations	**2,297**	2,684
Other regulatory liabilities	**169**	239
Liabilities held for sale	**2,836**	—
Other deferred credits and liabilities	**465**	691
Total deferred credits and other liabilities	**32,562**	27,097
Total Liabilities	**87,584**	85,153
Redeemable Preferred Stock of Subsidiaries (See accompanying statements)	**291**	324
Total Stockholders' Equity (See accompanying statements)	**29,039**	25,528
Total Liabilities and Stockholders' Equity	**$ 116,914**	$ 111,005
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, 2018 and 2017
Southern Company and Subsidiary Companies 2018 Annual Report

		2018	2017	2018	2017
		(in millions)		*(percent of total)*	
Long-Term Debt:					
Long-term debt payable to affiliated trusts —					
Variable rate (5.50% at 12/31/18) due 2042		**$ 206**	$ 206		
Long-term senior notes and debt —					
Maturity	Interest Rates				
2018	1.50% to 5.40%	**—**	2,352		
2019	1.85% to 5.55%	**2,948**	3,074		
2020	2.00% to 4.75%	**2,271**	2,273		
2021	2.35% to 9.10%	**2,638**	2,643		
2022	1.00% to 8.70%	**1,983**	2,016		
2023	2.45% to 5.75%	**2,290**	2,290		
2025 through 2048	1.63% to 7.30%	**19,895**	19,902		
Variable rates (2.29% to 3.05% at 12/31/17) due 2018		**—**	1,420		
Variable rates (3.10% to 3.50% at 12/31/18) due 2020		**1,875**	825		
Variable rates (3.34% to 3.91% at 12/31/18) due 2021		**125**	25		
Total long-term senior notes and debt		**34,025**	36,820		
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	1.15% to 2.60%	**33**	33		
2025 through 2049	1.40% to 5.15%	**1,112**	1,346		
Variable rates (1.77% to 2.23% at 12/31/18) due 2019		**148**	148		
Variable rates (1.76% to 1.87% at 12/31/18) due 2021		**65**	65		
Variable rates (1.76% at 12/31/18) due 2022		**4**	4		
Variable rates (1.70% to 1.87% at 12/31/18) due 2024 to 2053		**1,417**	1,585		
Plant Daniel revenue bonds (7.13%) due 2021		**270**	270		
Gas facility revenue bonds —					
Variable rate (1.71% at 12/31/17) due 2022		**—**	47		
Variable rate (1.71% at 12/31/17) due 2024 to 2033		**—**	154		
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		**44**	44		
2.57% to 3.86% due 2024 to 2044		**2,449**	2,449		
First mortgage bonds —					
4.70% due 2019		**50**	50		
5.80% due 2023		**50**	50		
2.66% to 6.58% due 2026 to 2058		**1,225**	925		
Junior subordinated notes (5.00% to 6.25%) due 2057 to 2077		**3,570**	3,570		
Total other long-term debt		**10,684**	10,987		
Unamortized fair value adjustment of long-term debt		**474**	525		
Capitalized lease obligations		**197**	204		
Unamortized debt premium		**36**	44		
Unamortized debt discount		**(194)**	(206)		
Unamortized debt issuance expense		**(208)**	(226)		
Total long-term debt (annual interest requirement — $1.7 billion)		**45,220**	48,354		
Less:					
Amount due within one year		**3,198**	3,892		
Amount held for sale		**1,286**	—		
Long-term debt excluding amounts due within one year and held for sale		**40,736**	44,462	**58.1%**	63.2%

CONSOLIDATED STATEMENTS OF CAPITALIZATION (continued)
At December 31, 2018 and 2017
Southern Company and Subsidiary Companies 2018 Annual Report

	2018	2017	2018	2017
	(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 — 2018: 475,115 shares				
— 2017: 809,325 shares	**48**	81		
$1 par value — 5.83%				
Authorized — 28 million shares				
Outstanding — 10,000,000 shares	**243**	243		
Total redeemable preferred stock of subsidiaries				
(annual dividend requirement — $15 million)	**291**	324	**0.4**	0.5
Common Stockholders' Equity:				
Common stock, par value $5 per share —	**5,164**	5,038		
Authorized — 1.5 billion shares				
Issued — 2018: 1.0 billion shares				
— 2017: 1.0 billion shares				
Treasury — 2018: 1.0 million shares				
— 2017: 0.9 million shares				
Paid-in capital	**11,094**	10,469		
Treasury, at cost	**(38)**	(36)		
Retained earnings	**8,706**	8,885		
Accumulated other comprehensive loss	**(203)**	(189)		
Total common stockholders' equity	**24,723**	24,167	**35.3**	34.4
Noncontrolling interests	**4,316**	1,361	**6.2**	1.9
Total stockholders' equity	**29,039**	25,528		
Total Capitalization	**$ 70,066**	$ 70,314	**100.0%**	100.0%

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

CONSOLIDATED STATEMENTS OF STOCKHOLDERS' EQUITY
For the Years Ended December 31, 2018, 2017, and 2016
Southern Company and Subsidiary Companies 2018 Annual Report

	Southern Company Common Stockholders' Equity									
	Number of Common Shares		Common Stock							
	Issued	Treasury	Par Value	Paid-In Capital	Treasury	Retained Earnings	Accumulated Other Comprehensive Income (Loss)	Preferred and Preference Stock of Subsidiaries	Noncontrolling Interests[a]	Total
	(in thousands)					*(in millions)*				
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 interests	—	—	—	—	—	—	—	—	114	114
Other	—	(110)	—	(4)	(5)	(13)	—	—	1	(21)
Balance at December 31, 2017	**1,008,532**	**(929)**	**5,038**	**10,469**	**(36)**	**8,885**	**(189)**	**—**	**1,361**	**25,528**
Consolidated net income attributable to Southern Company	**—**	**—**	**—**	**—**	**—**	**2,226**	**—**	**—**	**—**	**2,226**
Other comprehensive income (loss)	**—**	**—**	**—**	**—**	**—**	**—**	**26**	**—**	**—**	**26**
Stock issued	**26,209**	**—**	**126**	**964**	**—**	**—**	**—**	**—**	**—**	**1,090**
Stock-based compensation	**—**	**—**	**—**	**84**	**—**	**—**	**—**	**—**	**—**	**84**
Cash dividends of $2.3800 per share	**—**	**—**	**—**	**—**	**—**	**(2,425)**	**—**	**—**	**—**	**(2,425)**
Contributions from noncontrolling interests	**—**	**—**	**—**	**—**	**—**	**—**	**—**	**—**	**1,372**	**1,372**
Distributions to noncontrolling interests	**—**	**—**	**—**	**—**	**—**	**—**	**—**	**—**	**(164)**	**(164)**
Net income attributable to noncontrolling interests	**—**	**—**	**—**	**—**	**—**	**—**	**—**	**—**	**58**	**58**
Sale of noncontrolling interests	**—**	**—**	**—**	**(417)**	**—**	**—**	**—**	**—**	**1,690**	**1,273**
Other	**—**	**(24)**	**—**	**(6)**	**(2)**	**20**	**(40)**	**—**	**(1)**	**(29)**
Balance at December 31, 2018	**1,034,741**	**(953)**	**$5,164**	**$ 11,094**	**$ (38)**	**$ 8,706**	**$ (203)**	**$ —**	**$ 4,316**	**$ 29,039**

(a) Excludes redeemable noncontrolling interests. See Note 7 to the financial statements under "Noncontrolling Interests" for additional information.

The accompanying notes are an integral part of these consolidated 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 Statements

We have audited the accompanying balance sheets and statements of capitalization of Alabama Power Company (Alabama Power) (a wholly-owned subsidiary of The Southern Company) as of December 31, 2018 and 2017, 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, 2018, and the related notes (collectively referred to as the "financial statements"). In our opinion, the financial statements present fairly, in all material respects, the financial position of Alabama Power as of December 31, 2018 and 2017, and the results of its operations and its cash flows for each of the three years in the period ended December 31, 2018, in conformity with accounting principles generally accepted in the United States of America.

Basis for Opinion

These financial statements are the responsibility of Alabama Power's management. Our responsibility is to express an opinion on Alabama Power'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 Alabama Power 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. Alabama Power 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 Alabama Power'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 19, 2019

We have served as Alabama Power's auditor since 2002.

STATEMENTS OF INCOME
For the Years Ended December 31, 2018, 2017, and 2016
Alabama Power Company 2018 Annual Report

	2018	2017	2016
		(in millions)	
Operating Revenues:			
Retail revenues	**$ 5,367**	$ 5,458	$ 5,322
Wholesale revenues, non-affiliates	**279**	276	283
Wholesale revenues, affiliates	**119**	97	69
Other revenues	**267**	208	215
Total operating revenues	**6,032**	6,039	5,889
Operating Expenses:			
Fuel	**1,301**	1,225	1,297
Purchased power, non-affiliates	**216**	170	166
Purchased power, affiliates	**216**	158	168
Other operations and maintenance	**1,669**	1,709	1,557
Depreciation and amortization	**764**	736	703
Taxes other than income taxes	**389**	384	380
Total operating expenses	**4,555**	4,382	4,271
Operating Income	**1,477**	1,657	1,618
Other Income and (Expense):			
Allowance for equity funds used during construction	**62**	39	28
Interest expense, net of amounts capitalized	**(323)**	(305)	(302)
Other income (expense), net	**20**	43	26
Total other income and (expense)	**(241)**	(223)	(248)
Earnings Before Income Taxes	**1,236**	1,434	1,370
Income taxes	**291**	568	531
Net Income	**945**	866	839
Dividends on Preferred and Preference Stock	**15**	18	17
Net Income After Dividends on Preferred and Preference Stock	**$ 930**	$ 848	$ 822

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

STATEMENTS OF COMPREHENSIVE INCOME
For the Years Ended December 31, 2018, 2017, and 2016
Alabama Power Company 2018 Annual Report

	2018	2017	2016
		(in millions)	
Net Income	**$ 945**	$ 866	$ 839
Other comprehensive income (loss):			
Qualifying hedges:			
Changes in fair value, net of tax of $-, $(1), and $(1), respectively	—	1	(2)
Reclassification adjustment for amounts included in net income, net of tax of $2, $2, and $2, respectively	**4**	3	4
Total other comprehensive income (loss)	**4**	4	2
Comprehensive Income	**$ 949**	$ 870	$ 841

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

STATEMENTS OF CASH FLOWS
For the Years Ended December 31, 2018, 2017, and 2016
Alabama Power Company 2018 Annual Report

	2018	2017	2016
		(in millions)	
Operating Activities:			
Net income	**$ 945**	$ 866	$ 839
Adjustments to reconcile net income to net cash provided from operating activities —			
Depreciation and amortization, total	**917**	888	844
Deferred income taxes	**174**	409	407
Allowance for equity funds used during construction	**(62)**	(39)	(28)
Pension and postretirement funding	**(4)**	(2)	(133)
Settlement of asset retirement obligations	**(55)**	(26)	(25)
Other, net	**(1)**	13	(77)
Changes in certain current assets and liabilities —			
-Receivables	**(149)**	(168)	94
-Prepayments	**(2)**	(2)	1
-Materials and supplies	**(82)**	(34)	(38)
-Other current assets	**30**	20	38
-Accounts payable	**24**	71	73
-Accrued taxes	**10**	(84)	93
-Accrued compensation	**8**	(2)	12
-Retail fuel cost over recovery	**—**	(76)	(162)
-Other current liabilities	**128**	3	11
Net cash provided from operating activities	**1,881**	1,837	1,949
Investing Activities:			
Property additions	**(2,158)**	(1,882)	(1,272)
Nuclear decommissioning trust fund purchases	**(279)**	(237)	(352)
Nuclear decommissioning trust fund sales	**278**	237	351
Cost of removal net of salvage	**(130)**	(112)	(94)
Change in construction payables	**26**	161	(37)
Other investing activities	**(26)**	(43)	(34)
Net cash used for investing activities	**(2,289)**	(1,876)	(1,438)
Financing Activities:			
Proceeds —			
Senior notes	**500**	1,100	400
Preferred stock	**—**	250	—
Pollution control revenue bonds	**120**	—	—
Other long-term debt	**—**	—	45
Capital contributions from parent company	**511**	361	260
Redemptions and repurchases —			
Senior notes	**—**	(525)	(200)
Preferred and preference stock	**—**	(238)	—
Pollution control revenue bonds	**(120)**	(36)	—
Payment of common stock dividends	**(801)**	(714)	(765)
Other financing activities	**(33)**	(35)	(25)
Net cash provided from (used for) financing activities	**177**	163	(285)
Net Change in Cash, Cash Equivalents, and Restricted Cash	**(231)**	124	226
Cash, Cash Equivalents, and Restricted Cash at Beginning of Year	**544**	420	194
Cash, Cash Equivalents, and Restricted Cash at End of Year	**$ 313**	$ 544	$ 420
Supplemental Cash Flow Information:			
Cash paid (received) during the period for —			
Interest (net of $22, $15, and $11 capitalized, respectively)	**$ 284**	$ 285	$ 277
Income taxes (net of refunds)	**106**	236	(108)
Noncash transactions — Accrued property additions at year-end	**272**	245	84

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

BALANCE SHEETS
At December 31, 2018 and 2017
Alabama Power Company 2018 Annual Report

Assets	**2018**	2017
		(in millions)
Current Assets:		
Cash and cash equivalents	**$ 313**	$ 544
Receivables —		
Customer accounts receivable	**403**	355
Unbilled revenues	**150**	162
Affiliated	**94**	43
Other accounts and notes receivable	**51**	55
Accumulated provision for uncollectible accounts	**(10)**	(9)
Fossil fuel stock	**141**	184
Materials and supplies	**546**	458
Prepaid expenses	**66**	85
Other regulatory assets, current	**137**	124
Other current assets	**18**	5
Total current assets	**1,909**	2,006
Property, Plant, and Equipment:		
In service	**30,402**	27,326
Less: Accumulated provision for depreciation	**9,988**	9,563
Plant in service, net of depreciation	**20,414**	17,763
Nuclear fuel, at amortized cost	**324**	339
Construction work in progress	**1,113**	908
Total property, plant, and equipment	**21,851**	19,010
Other Property and Investments:		
Equity investments in unconsolidated subsidiaries	**65**	67
Nuclear decommissioning trusts, at fair value	**847**	903
Miscellaneous property and investments	**127**	124
Total other property and investments	**1,039**	1,094
Deferred Charges and Other Assets:		
Deferred charges related to income taxes	**240**	239
Deferred under recovered regulatory clause revenues	**116**	54
Other regulatory assets, deferred	**1,386**	1,272
Other deferred charges and assets	**189**	189
Total deferred charges and other assets	**1,931**	1,754
Total Assets	**$ 26,730**	$ 23,864

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

BALANCE SHEETS
At December 31, 2018 and 2017
Alabama Power Company 2018 Annual Report

Liabilities and Stockholder's Equity		**2018**		2017
				(in millions)
Current Liabilities:				
Securities due within one year	**$**	**201**	$	—
Accounts payable —				
Affiliated		**364**		327
Other		**614**		585
Customer deposits		**96**		92
Accrued taxes		**44**		54
Accrued interest		**89**		77
Accrued compensation		**227**		205
Asset retirement obligations, current		**163**		7
Other current liabilities		**161**		53
Total current liabilities		**1,959**		1,400
Long-Term Debt (See accompanying statements)		**7,923**		7,628
Deferred Credits and Other Liabilities:				
Accumulated deferred income taxes		**2,962**		2,760
Deferred credits related to income taxes		**2,027**		2,082
Accumulated deferred ITCs		**106**		112
Employee benefit obligations		**314**		304
Asset retirement obligations		**3,047**		1,702
Other cost of removal obligations		**497**		609
Other regulatory liabilities, deferred		**69**		84
Other deferred credits and liabilities		**58**		63
Total deferred credits and other liabilities		**9,080**		7,716
Total Liabilities		**18,962**		16,744
Redeemable Preferred Stock (See accompanying statements)		**291**		291
Common Stockholder's Equity (See accompanying statements)		**7,477**		6,829
Total Liabilities and Stockholder's Equity	**$**	**26,730**	$	23,864
Commitments and Contingent Matters (See notes)				

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

STATEMENTS OF CAPITALIZATION
At December 31, 2018 and 2017
Alabama Power Company 2018 Annual Report

	2018	2017	2018	2017
	(in millions)		*(percent of total)*	
Long-Term Debt:				
Long-term debt payable to affiliated trusts —				
Variable rate (5.50% at 12/31/18) due 2042	**$ 206**	$ 206		
Long-term notes payable —				
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**	750		
3.55% due 2023	**300**	300		
2.80% to 6.125% due 2025-2048	**5,175**	4,675		
Variable rates (3.70% to 3.91% at 12/31/18) due 2021	**25**	25		
Total long-term notes payable	**6,920**	6,420		
Other long-term debt —				
Pollution control revenue bonds —				
1.625% to 2.90% due 2034	**207**	207		
Variable rates (1.76% to 1.87% at 12/31/18) due 2021	**65**	65		
Variable rates (1.70% to 1.80% at 12/31/18) due 2024-2038	**788**	788		
Total other long-term debt	**1,060**	1,060		
Capitalized lease obligations	**4**	4		
Unamortized debt premium (discount), net	**(12)**	(11)		
Unamortized debt issuance expense	**(54)**	(51)		
Total long-term debt (annual interest requirement — $330 million)	**8,124**	7,628		
Less amount due within one year	**201**	—		
Long-term debt excluding amount due within one year	**7,923**	7,628	**50.4%**	51.7%
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 — 5.00%				
Authorized — 27,500,000 shares				
Outstanding — 10,000,000 shares: $25 stated value	**243**	243		
Total redeemable preferred stock (annual dividend requirement — $15 million)	**291**	291	**1.9**	2.0
Common Stockholder's Equity:				
Common stock, par value $40 per share —				
Authorized — 40,000,000 shares				
Outstanding — 30,537,500 shares	**1,222**	1,222		
Paid-in capital	**3,508**	2,986		
Retained earnings	**2,775**	2,647		
Accumulated other comprehensive loss	**(28)**	(26)		
Total common stockholder's equity	**7,477**	6,829	**47.7**	46.3
Total Capitalization	**$ 15,691**	$ 14,748	**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, 2018, 2017, and 2016
Alabama Power Company 2018 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, 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**
Net income after dividends on preferred and preference stock	—	—	—	**930**	—	**930**
Capital contributions from parent company	—	—	**522**	—	—	**522**
Other comprehensive income (loss)	—	—	—	—	**4**	**4**
Cash dividends on common stock	—	—	—	**(801)**	—	**(801)**
Other	—	—	—	**(1)**	**(6)**	**(7)**
Balance at December 31, 2018	**31**	**$ 1,222**	**$ 3,508**	**$ 2,775**	**$ (28)**	**$ 7,477**

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

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 (Georgia Power) (a wholly-owned subsidiary of The Southern Company) as of December 31, 2018 and 2017, 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, 2018, and the related notes (collectively referred to as the "financial statements"). In our opinion, the financial statements present fairly, in all material respects, the financial position of Georgia Power as of December 31, 2018 and 2017, and the results of its operations and its cash flows for each of the three years in the period ended December 31, 2018, in conformity with accounting principles generally accepted in the United States of America.

Basis for Opinion

These financial statements are the responsibility of Georgia Power's management. Our responsibility is to express an opinion on Georgia Power'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 Georgia Power 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. Georgia Power 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 Georgia Power'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 19, 2019

We have served as Georgia Power's auditor since 2002.

STATEMENTS OF INCOME
For the Years Ended December 31, 2018, 2017, and 2016
Georgia Power Company 2018 Annual Report

	2018	2017	2016
		(in millions)	
Operating Revenues:			
Retail revenues	**$ 7,752**	$ 7,738	$ 7,772
Wholesale revenues, non-affiliates	**163**	163	175
Wholesale revenues, affiliates	**24**	26	42
Other revenues	**481**	383	394
Total operating revenues	**8,420**	8,310	8,383
Operating Expenses:			
Fuel	**1,698**	1,671	1,807
Purchased power, non-affiliates	**430**	416	361
Purchased power, affiliates	**723**	622	518
Other operations and maintenance	**1,860**	1,724	2,003
Depreciation and amortization	**923**	895	855
Taxes other than income taxes	**437**	409	405
Estimated loss on Plant Vogtle Units 3 and 4	**1,060**	—	—
Total operating expenses	**7,131**	5,737	5,949
Operating Income	**1,289**	2,573	2,434
Other Income and (Expense):			
Interest expense, net of amounts capitalized	**(397)**	(419)	(388)
Other income (expense), net	**115**	104	81
Total other income and (expense)	**(282)**	(315)	(307)
Earnings Before Income Taxes	**1,007**	2,258	2,127
Income taxes	**214**	830	780
Net Income	**793**	1,428	1,347
Dividends on Preferred and Preference Stock	**—**	14	17
Net Income After Dividends on Preferred and Preference Stock	**$ 793**	$ 1,414	$ 1,330

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

STATEMENTS OF COMPREHENSIVE INCOME
For the Years Ended December 31, 2018, 2017, and 2016
Georgia Power Company 2018 Annual Report

	2018	2017	2016
		(in millions)	
Net Income	**$ 793**	$ 1,428	$ 1,347
Other comprehensive income (loss):			
Qualifying hedges:			
Reclassification adjustment for amounts included in net income, net of tax of $1, $1, and $2, respectively	**3**	3	2
Total other comprehensive income (loss)	**3**	3	2
Comprehensive Income	**$ 796**	$ 1,431	$ 1,349

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

STATEMENTS OF CASH FLOWS
For the Years Ended December 31, 2018, 2017, and 2016
Georgia Power Company 2018 Annual Report

	2018	2017	2016
		(in millions)	
Operating Activities:			
Net income	**$ 793**	$ 1,428	$ 1,347
Adjustments to reconcile net income to net cash provided from operating activities —			
Depreciation and amortization, total	**1,142**	1,100	1,063
Deferred income taxes	**(260)**	458	383
Pension, postretirement, and other employee benefits	**(75)**	(68)	(33)
Pension and postretirement funding	**—**	—	(287)
Settlement of asset retirement obligations	**(116)**	(120)	(123)
Other deferred charges — affiliated	**—**	—	(111)
Estimated loss on Plant Vogtle Units 3 and 4	**1,060**	—	—
Other, net	**(21)**	(83)	(25)
Changes in certain current assets and liabilities —			
-Receivables	**8**	(256)	60
-Fossil fuel stock	**83**	(16)	104
-Prepaid income taxes	**152**	(168)	—
-Other current assets	**(43)**	(28)	(38)
-Accounts payable	**95**	(219)	(42)
-Accrued taxes	**58**	1	131
-Retail fuel cost over recovery	**—**	(84)	(32)
-Other current liabilities	**(107)**	(33)	28
Net cash provided from operating activities	**2,769**	1,912	2,425
Investing Activities:			
Property additions	**(3,116)**	(2,704)	(2,223)
Proceeds pursuant to the Toshiba Guarantee, net of joint owner portion	**—**	1,682	—
Nuclear decommissioning trust fund purchases	**(839)**	(574)	(808)
Nuclear decommissioning trust fund sales	**833**	568	803
Cost of removal, net of salvage	**(107)**	(100)	(83)
Change in construction payables, net of joint owner portion	**68**	223	(35)
Payments pursuant to LTSAs	**(54)**	(64)	(34)
Proceeds from asset dispositions	**138**	96	10
Other investing activities	**(32)**	(39)	23
Net cash used for investing activities	**(3,109)**	(912)	(2,347)
Financing Activities:			
Increase (decrease) in notes payable, net	**294**	(391)	234
Proceeds —			
Capital contributions from parent company	**2,985**	431	594
Senior notes	**—**	1,350	650
Short-term borrowings	**—**	700	—
Other long-term debt	**—**	370	—
FFB loan	**—**	—	425
Pollution control revenue bonds issuances and remarketings	**108**	65	—
Redemptions and repurchases —			
Senior notes	**(1,500)**	(450)	(700)
Pollution control revenue bonds	**(469)**	(65)	(4)
Short-term borrowings	**(150)**	(550)	—
Preferred and preference stock	**—**	(270)	—
Other long-term debt	**(100)**	—	—
Payment of common stock dividends	**(1,396)**	(1,281)	(1,305)
Premiums on redemption and repurchases of senior notes	**(152)**	—	—
Other financing activities	**(20)**	(60)	(36)
Net cash used for financing activities	**(400)**	(151)	(142)
Net Change in Cash, Cash Equivalents, and Restricted Cash	**(740)**	849	(64)
Cash, Cash Equivalents, and Restricted Cash at Beginning of Year	**852**	3	67
Cash, Cash Equivalents, and Restricted Cash at End of Year	**$ 112**	$ 852	$ 3
Supplemental Cash Flow Information:			
Cash paid during the period for —			
Interest (net of $26, $23, and $20 capitalized, respectively)	**$ 408**	$ 386	$ 375
Income taxes (net of refunds)	**300**	496	170
Noncash transactions — Accrued property additions at year-end	**683**	550	336

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

BALANCE SHEETS
At December 31, 2018 and 2017
Georgia Power Company 2018 Annual Report

Assets	2018	2017
		(in millions)
Current Assets:		
Cash and cash equivalents	**$ 4**	$ 852
Restricted cash	**108**	—
Receivables —		
Customer accounts receivable	**591**	544
Unbilled revenues	**208**	255
Under recovered fuel clause revenues	**115**	165
Joint owner accounts receivable	**170**	262
Affiliated	**39**	24
Other accounts and notes receivable	**80**	76
Accumulated provision for uncollectible accounts	**(2)**	(3)
Fossil fuel stock	**231**	314
Materials and supplies	**519**	504
Prepaid expenses	**142**	216
Other regulatory assets, current	**199**	205
Other current assets	**70**	14
Total current assets	**2,474**	3,428
Property, Plant, and Equipment:		
In service	**37,675**	34,861
Less: Accumulated provision for depreciation	**12,096**	11,704
Plant in service, net of depreciation	**25,579**	23,157
Nuclear fuel, at amortized cost	**550**	544
Construction work in progress	**4,833**	4,613
Total property, plant, and equipment	**30,962**	28,314
Other Property and Investments:		
Equity investments in unconsolidated subsidiaries	**51**	53
Nuclear decommissioning trusts, at fair value	**873**	929
Miscellaneous property and investments	**72**	59
Total other property and investments	**996**	1,041
Deferred Charges and Other Assets:		
Deferred charges related to income taxes	**517**	516
Other regulatory assets, deferred	**4,902**	2,932
Other deferred charges and assets	**514**	548
Total deferred charges and other assets	**5,933**	3,996
Total Assets	**$ 40,365**	$ 36,779

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

BALANCE SHEETS
At December 31, 2018 and 2017
Georgia Power Company 2018 Annual Report

Liabilities and Stockholder's Equity		**2018**		2017
			(in millions)	
Current Liabilities:				
Securities due within one year	**$**	**617**	$	857
Notes payable		**294**		150
Accounts payable —				
Affiliated		**575**		493
Other		**890**		834
Customer deposits		**276**		270
Accrued taxes		**377**		344
Accrued interest		**105**		123
Accrued compensation		**221**		219
Asset retirement obligations, current		**202**		270
Other regulatory liabilities, current		**169**		191
Other current liabilities		**183**		198
Total current liabilities		**3,909**		3,949
Long-Term Debt (See accompanying statements)		**9,364**		11,073
Deferred Credits and Other Liabilities:				
Accumulated deferred income taxes		**3,062**		3,175
Deferred credits related to income taxes		**3,080**		3,248
Accumulated deferred ITCs		**262**		248
Employee benefit obligations		**599**		659
Asset retirement obligations, deferred		**5,627**		2,368
Other deferred credits and liabilities		**139**		128
Total deferred credits and other liabilities		**12,769**		9,826
Total Liabilities		**26,042**		24,848
Common Stockholder's Equity (See accompanying statements)		**14,323**		11,931
Total Liabilities and Stockholder's Equity	**$**	**40,365**	$	36,779
Commitments and Contingent Matters (See notes)				

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

STATEMENTS OF CAPITALIZATION
At December 31, 2018 and 2017
Georgia Power Company 2018 Annual Report

	2018	2017	2018	2017
		(in millions)	*(percent of total)*	
Long-Term Debt:				
Long-term notes payable —				
1.95% to 5.40% due 2018	**$ —**	$ 747		
4.25% due 2019	**498**	499		
2.00% due 2020	**950**	950		
2.40% due 2021	**325**	325		
2.85% due 2022	**400**	400		
5.75% due 2023	**100**	100		
3.25% to 5.95% due 2026-2043	**3,325**	4,075		
Variable rate (2.29% at 12/31/17) due 2018	**—**	100		
Total long-term notes payable	**5,598**	7,196		
Other long-term debt —				
Pollution control revenue bonds —				
2.35% due 2022	**53**	53		
1.55% to 4.00% due 2025-2049	**748**	940		
Variable rate (1.77% to 1.78% at 12/31/18) due 2019	**108**	108		
Variable rates (1.70% to 1.83% at 12/31/18) due 2026-2052	**551**	720		
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	**44**	44		
2.57% to 3.86% due 2024-2044	**2,449**	2,449		
Junior subordinated note (5.00%) due 2077	**270**	270		
Total other long-term debt	**4,355**	4,716		
Capitalized lease obligations	**142**	154		
Unamortized debt premium (discount), net	**(6)**	(12)		
Unamortized debt issuance expense	**(108)**	(124)		
Total long-term debt (annual interest requirement — $356 million)	**9,981**	11,930		
Less amount due within one year	**617**	857		
Long-term debt excluding amount due within one year	**9,364**	11,073	**39.5%**	48.1%
Common Stockholder's Equity:				
Common stock, without par value —				
Authorized — 20,000,000 shares				
Outstanding — 9,261,500 shares	**398**	398		
Paid-in capital	**10,322**	7,328		
Retained earnings	**3,612**	4,215		
Accumulated other comprehensive loss	**(9)**	(10)		
Total common stockholder's equity	**14,323**	11,931	**60.5**	51.9
Total Capitalization	**$ 23,687**	$ 23,004	**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, 2018, 2017, and 2016
Georgia Power Company 2018 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, 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**
Net income after dividends on preferred and preference stock	**—**	**—**	**—**	**793**	**—**	**793**
Capital contributions from parent company	—	—	**2,994**	—	—	**2,994**
Other comprehensive income (loss)	**—**	**—**	**—**	**—**	**3**	**3**
Cash dividends on common stock	—	—	—	**(1,396)**	—	**(1,396)**
Other	**—**	**—**	**—**	**—**	**(2)**	**(2)**
Balance at December 31, 2018	**9**	**$ 398**	**$ 10,322**	**$ 3,612**	**$ (9)**	**$ 14,323**

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

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the stockholder 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 (Mississippi Power) (a wholly-owned subsidiary of The Southern Company) as of December 31, 2018 and 2017, 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, 2018, and the related notes (collectively referred to as the "financial statements"). In our opinion, the financial statements present fairly, in all material respects, the financial position of Mississippi Power as of December 31, 2018 and 2017, and the results of its operations and its cash flows for each of the three years in the period ended December 31, 2018, in conformity with accounting principles generally accepted in the United States of America.

Basis for Opinion

These financial statements are the responsibility of Mississippi Power's management. Our responsibility is to express an opinion on Mississippi Power'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 Mississippi Power 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. Mississippi Power 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 Mississippi Power'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 19, 2019

We have served as Mississippi Power's auditor since 2002.

STATEMENTS OF OPERATIONS
For the Years Ended December 31, 2018, 2017, and 2016
Mississippi Power Company 2018 Annual Report

	2018	2017	2016
		(in millions)	
Operating Revenues:			
Retail revenues	**$ 889**	$ 854	$ 859
Wholesale revenues, non-affiliates	**263**	259	261
Wholesale revenues, affiliates	**91**	56	26
Other revenues	**22**	18	17
Total operating revenues	**1,265**	1,187	1,163
Operating Expenses:			
Fuel	**405**	395	343
Purchased power	**41**	25	34
Other operations and maintenance	**313**	291	317
Depreciation and amortization	**169**	161	132
Taxes other than income taxes	**107**	104	109
Estimated loss on Kemper IGCC	**37**	3,362	428
Total operating expenses	**1,072**	4,338	1,363
Operating Income (Loss)	**193**	(3,151)	(200)
Other Income and (Expense):			
Allowance for equity funds used during construction	**—**	72	124
Interest expense, net of amounts capitalized	**(76)**	(42)	(74)
Other income (expense), net	**17**	1	(2)
Total other income and (expense)	**(59)**	31	48
Earnings (Loss) Before Income Taxes	**134**	(3,120)	(152)
Income taxes (benefit)	**(102)**	(532)	(104)
Net Income (Loss)	**236**	(2,588)	(48)
Dividends on Preferred Stock	**1**	2	2
Net Income (Loss) After Dividends on Preferred Stock	**$ 235**	$ (2,590)	$ (50)

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

STATEMENTS OF COMPREHENSIVE INCOME (LOSS)
For the Years Ended December 31, 2018, 2017, and 2016
Mississippi Power Company 2018 Annual Report

	2018	2017	2016
		(in millions)	
Net Income (Loss)	**$ 236**	$ (2,588)	$ (48)
Other comprehensive income (loss):			
Qualifying hedges:			
Changes in fair value, net of tax of $(1), $(1), and $1, respectively	**(1)**	(1)	1
Reclassification adjustment for amounts included in net income, net of tax of $-, $1, and $1, respectively	**1**	1	1
Total other comprehensive income (loss)	**—**	—	2
Comprehensive Income (Loss)	**$ 236**	$ (2,588)	$ (46)

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

STATEMENTS OF CASH FLOWS
For the Years Ended December 31, 2018, 2017, and 2016
Mississippi Power Company 2018 Annual Report

	2018	2017	2016
		(in millions)	
Operating Activities:			
Net income (loss)	**$ 236**	$ (2,588)	$ (48)
Adjustments to reconcile net income (loss) to net cash provided from operating activities —			
Depreciation and amortization, total	**177**	198	157
Deferred income taxes	**475**	(727)	(67)
Allowance for equity funds used during construction	**—**	(72)	(124)
Pension and postretirement funding	**—**	—	(47)
Settlement of asset retirement obligations	**(35)**	(23)	(23)
Estimated loss on Kemper IGCC	**33**	3,179	428
Other, net	**18**	(8)	(9)
Changes in certain current assets and liabilities —			
-Receivables	**(19)**	540	13
-Fossil fuel stock	**(3)**	24	4
-Prepaid income taxes	**(12)**	—	39
-Other current assets	**(7)**	(13)	(12)
-Accounts payable	**15**	(3)	(14)
-Accrued interest	**(1)**	(29)	27
-Accrued taxes	**(46)**	80	14
-Over recovered regulatory clause revenues	**14**	(51)	(45)
-Customer liability associated with Kemper refunds	**—**	(1)	(73)
-Other current liabilities	**(41)**	(3)	9
Net cash provided from operating activities	**804**	503	229
Investing Activities:			
Property additions	**(188)**	(429)	(798)
Construction payables	**4**	(47)	(26)
Government grant proceeds	**—**	—	137
Payments pursuant to LTSAs	**(29)**	(10)	10
Other investing activities	**(19)**	(18)	(20)
Net cash used for investing activities	**(232)**	(504)	(697)
Financing Activities:			
Decrease in notes payable, net	**(4)**	(18)	—
Proceeds —			
Capital contributions from parent company	**15**	1,002	627
Senior notes	**600**	—	—
Long-term debt issuance to parent company	**—**	40	200
Other long-term debt	**—**	—	1,200
Short-term borrowings	**300**	109	—
Redemptions —			
Preferred stock	**(33)**	—	—
Pollution control revenue bonds	**(43)**	—	—
Short-term borrowings	**(300)**	(109)	(478)
Long-term debt to parent company	**—**	(591)	(225)
Capital leases	**—**	(71)	(3)
Senior notes	**(155)**	(35)	(300)
Other long-term debt	**(900)**	(300)	(425)
Other financing activities	**(7)**	(2)	(2)
Net cash provided from (used for) financing activities	**(527)**	25	594
Net Change in Cash, Cash Equivalents, and Restricted Cash	**45**	24	126
Cash, Cash Equivalents, and Restricted Cash at Beginning of Year	**248**	224	98
Cash, Cash Equivalents, and Restricted Cash at End of Year	**$ 293**	$ 248	$ 224
Supplemental Cash Flow Information:			
Cash paid (received) during the period for —			
Interest (net of $-, $29, and $49 capitalized, respectively)	**$ 80**	$ 65	$ 50
Income taxes (net of refunds)	**(525)**	(424)	(97)
Noncash transactions — Accrued property additions at year-end	**35**	32	78

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

BALANCE SHEETS
At December 31, 2018 and 2017
Mississippi Power Company 2018 Annual Report

Assets	2018	2017
		(in millions)
Current Assets:		
Cash and cash equivalents	**$ 293**	$ 248
Receivables —		
Customer accounts receivable	**34**	36
Unbilled revenues	**41**	41
Affiliated	**21**	16
Other accounts and notes receivable	**31**	16
Fossil fuel stock	**20**	17
Materials and supplies, current	**53**	44
Other regulatory assets, current	**116**	125
Prepaid income taxes	**12**	—
Other current assets	**7**	9
Total current assets	**628**	552
Property, Plant, and Equipment:		
In service	**4,900**	4,773
Less: Accumulated provision for depreciation	**1,429**	1,325
Plant in service, net of depreciation	**3,471**	3,448
Construction work in progress	**103**	84
Total property, plant, and equipment	**3,574**	3,532
Other Property and Investments	**24**	30
Deferred Charges and Other Assets:		
Deferred charges related to income taxes	**33**	35
Other regulatory assets, deferred	**474**	437
Accumulated deferred income taxes	**150**	247
Other deferred charges and assets	**3**	33
Total deferred charges and other assets	**660**	752
Total Assets	**$ 4,886**	$ 4,866

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

BALANCE SHEETS
At December 31, 2018 and 2017
Mississippi Power Company 2018 Annual Report

Liabilities and Stockholder's Equity	2018	2017
		(in millions)
Current Liabilities:		
Securities due within one year	**$ 40**	$ 989
Notes payable	**—**	4
Accounts payable —		
Affiliated	**60**	59
Other	**90**	96
Accrued taxes —		
Accrued income taxes	**—**	40
Other accrued taxes	**95**	101
Accrued interest	**15**	16
Accrued compensation	**38**	39
Accrued plant closure costs	**29**	35
Asset retirement obligations, current	**34**	37
Over recovered regulatory clause liabilities	**14**	—
Other current liabilities	**40**	47
Total current liabilities	**455**	1,463
Long-Term Debt (See accompanying statements)	**1,539**	1,097
Deferred Credits and Other Liabilities:		
Accumulated deferred income taxes	**378**	—
Deferred credits related to income taxes	**382**	372
Employee benefit obligations	**115**	116
Asset retirement obligations, deferred	**126**	137
Other cost of removal obligations	**185**	178
Other regulatory liabilities, deferred	**81**	79
Other deferred credits and liabilities	**16**	33
Total deferred credits and other liabilities	**1,283**	915
Total Liabilities	**3,277**	3,475
Cumulative Redeemable Preferred Stock (See accompanying statements)	**—**	33
Common Stockholder's Equity (See accompanying statements)	**1,609**	1,358
Total Liabilities and Stockholder's Equity	**$ 4,886**	$ 4,866
Commitments and Contingent Matters (See notes)		

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

STATEMENTS OF CAPITALIZATION
At December 31, 2018 and 2017
Mississippi Power Company 2018 Annual Report

	2018	2017	2018	2017
	(in millions)		*(percent of total)*	
Long-Term Debt:				
Long-term notes payable —				
5.55% due 2019	**$ —**	$ 125		
1.63% to 5.40% due 2028-2042	**950**	680		
Adjustable rate (3.05% at 12/31/17) due 2018	**—**	900		
Adjustable rate (3.47% at 12/31/18) due 2020	**300**	—		
Total long-term notes payable	**1,250**	1,705		
Other long-term debt —				
Pollution control revenue bonds —				
5.15% due 2028	**—**	43		
Variable rates (2.20% to 2.23% at 12/31/18) due 2019	**40**	40		
Plant Daniel revenue bonds (7.13%) due 2021	**270**	270		
Total other long-term debt	**310**	353		
Unamortized debt premium	**29**	36		
Unamortized debt discount	**(2)**	(1)		
Unamortized debt issuance expense	**(8)**	(7)		
Total long-term debt (annual interest requirement — $70 million)	**1,579**	2,086		
Less amount due within one year	**40**	989		
Long-term debt excluding amount due within one year	**1,539**	1,097	**48.9%**	44.1%
Cumulative Redeemable Preferred Stock:				
$100 par value — 4.40% to 5.25%				
Authorized — 1,244,139 shares				
Outstanding — 2018: no shares				
— 2017: 334,210 shares	**—**	33	**—**	1.3
Common Stockholder's Equity:				
Common stock, without par value —				
Authorized — 1,130,000 shares				
Outstanding — 1,121,000 shares	**38**	38		
Paid-in capital	**4,546**	4,529		
Accumulated deficit	**(2,971)**	(3,205)		
Accumulated other comprehensive loss	**(4)**	(4)		
Total common stockholder's equity	**1,609**	1,358	**51.1**	54.6
Total Capitalization	**$ 3,148**	$ 2,488	**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, 2018, 2017, and 2016
Mississippi Power Company 2018 Annual Report

	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, 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**
Net income after dividends on preferred stock	**—**	**—**	**—**	**235**	**—**	**235**
Capital contributions from parent company	**—**	**—**	**17**	**—**	**—**	**17**
Other	**—**	**—**	**—**	**(1)**	**—**	**(1)**
Balance at December 31, 2018	**1**	**$ 38**	**$ 4,546**	**$ (2,971)**	**$ (4)**	**$ 1,609**

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

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 (Southern Power) (a wholly-owned subsidiary of The Southern Company) as of December 31, 2018 and 2017, 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, 2018, and the related notes (collectively referred to as the "financial statements"). In our opinion, the financial statements present fairly, in all material respects, the financial position of Southern Power as of December 31, 2018 and 2017, and the results of its operations and its cash flows for each of the three years in the period ended December 31, 2018, in conformity with accounting principles generally accepted in the United States of America.

Basis for Opinion

These financial statements are the responsibility of Southern Power's management. Our responsibility is to express an opinion on Southern Power'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 Southern Power 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. Southern Power 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 Southern Power'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 19, 2019

We have served as Southern Power's auditor since 2002.

CONSOLIDATED STATEMENTS OF INCOME
For the Years Ended December 31, 2018, 2017, and 2016
Southern Power Company and Subsidiary Companies 2018 Annual Report

	2018	2017	2016
		(in millions)	
Operating Revenues:			
Wholesale revenues, non-affiliates	**$ 1,757**	$ 1,671	$ 1,146
Wholesale revenues, affiliates	**435**	392	419
Other revenues	**13**	12	12
Total operating revenues	**2,205**	2,075	1,577
Operating Expenses:			
Fuel	**699**	621	456
Purchased power	**176**	149	102
Other operations and maintenance	**395**	386	354
Depreciation and amortization	**493**	503	352
Taxes other than income taxes	**46**	48	23
Asset impairment	**156**	—	—
Gain on disposition	**(2)**	—	—
Total operating expenses	**1,963**	1,707	1,287
Operating Income	**242**	368	290
Other Income and (Expense):			
Interest expense, net of amounts capitalized	**(183)**	(191)	(117)
Other income (expense), net	**23**	1	6
Total other income and (expense)	**(160)**	(190)	(111)
Earnings Before Income Taxes	**82**	178	179
Income taxes (benefit)	**(164)**	(939)	(195)
Net Income	**246**	1,117	374
Net income attributable to noncontrolling interests	**59**	46	36
Net Income Attributable to Southern Power	**$ 187**	$ 1,071	$ 338

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

CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME
For the Years Ended December 31, 2018, 2017, and 2016
Southern Power Company and Subsidiary Companies 2018 Annual Report

	2018	2017	2016
		(in millions)	
Net Income	**$ 246**	$ 1,117	$ 374
Other comprehensive income (loss):			
Qualifying hedges:			
Changes in fair value, net of tax of $(17), $39, and $(17), respectively	**(51)**	63	(27)
Reclassification adjustment for amounts included in net income, net of tax of $19, $(46), and $36, respectively	**58**	(73)	58
Pension and other postretirement benefit plans:			
Benefit plan net gain (loss), net of tax of $2, $-, and $-, respectively	**5**	—	—
Reclassification adjustment for amounts included in net income, net of tax of $-, $-, and $-, respectively	**2**	—	—
Total other comprehensive income (loss)	**14**	(10)	31
Comprehensive income attributable to noncontrolling interests	**59**	46	36
Comprehensive Income Attributable to Southern Power	**$ 201**	$ 1,061	$ 369

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

CONSOLIDATED STATEMENTS OF CASH FLOWS
For the Years Ended December 31, 2018, 2017, and 2016
Southern Power Company and Subsidiary Companies 2018 Annual Report

	2018	2017	2016
		(in millions)	
Operating Activities:			
Net income	**$ 246**	$ 1,117	$ 374
Adjustments to reconcile net income to net cash provided from operating activities —			
Depreciation and amortization, total	**524**	536	370
Deferred income taxes	**(239)**	(263)	(1,063)
Amortization of investment tax credits	**(58)**	(57)	(37)
Collateral deposits	**17**	(4)	(102)
Accrued income taxes, non-current	**(14)**	14	(109)
Income taxes receivable, non-current	**42**	(61)	(13)
Asset impairment	**156**	—	—
Other, net	**(10)**	(9)	12
Changes in certain current assets and liabilities —			
-Receivables	**(20)**	(60)	(54)
-Prepaid income taxes	**25**	24	(29)
-Other current assets	**(26)**	(28)	4
-Accrued taxes	**7**	(55)	940
-Other current liabilities	**(19)**	1	46
Net cash provided from operating activities	**631**	1,155	339
Investing Activities:			
Business acquisitions	**(65)**	(1,016)	(2,284)
Property additions	**(315)**	(268)	(2,114)
Change in construction payables	**(6)**	(153)	(57)
Proceeds from disposition	**203**	—	—
Payments pursuant to LTSAs and for equipment not yet received	**(75)**	(203)	(350)
Other investing activities	**31**	15	16
Net cash used for investing activities	**(227)**	(1,625)	(4,789)
Financing Activities:			
Increase (decrease) in notes payable, net	**(105)**	(104)	73
Proceeds —			
Short-term borrowings	**200**	—	—
Capital contributions	**2**	—	1,850
Senior notes	**—**	525	2,831
Other long-term debt	**—**	43	65
Redemptions —			
Senior notes	**(350)**	(500)	(200)
Other long-term debt	**(420)**	(18)	(86)
Short-term borrowings	**(100)**	—	—
Return of capital	**(1,650)**	—	—
Distributions to noncontrolling interests	**(153)**	(119)	(57)
Capital contributions from noncontrolling interests	**2,551**	80	682
Purchase of membership interests from noncontrolling interests	**—**	(59)	(129)
Payment of common stock dividends	**(312)**	(317)	(272)
Other financing activities	**(26)**	(33)	(30)
Net cash provided from (used for) financing activities	**(363)**	(502)	4,727
Net Change in Cash, Cash Equivalents, and Restricted Cash	**41**	(972)	277
Cash, Cash Equivalents, and Restricted Cash at Beginning of Year	**140**	1,112	835
Cash, Cash Equivalents, and Restricted Cash at End of Year	**$ 181**	$ 140	$ 1,112
Supplemental Cash Flow Information:			
Cash paid (received) during the period for —			
Interest (net of $17, $11, and $44 capitalized, respectively)	**$ 173**	$ 189	$ 89
Income taxes (net of refunds and investment tax credits)	**79**	(487)	116
Noncash transactions —			
Accrued property additions at year-end	**31**	32	251
Accrued acquisitions at year-end	**—**	—	461

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

CONSOLIDATED BALANCE SHEETS
At December 31, 2018 and 2017
Southern Power Company and Subsidiary Companies 2018 Annual Report

Assets	**2018**	2017
		(in millions)
Current Assets:		
Cash and cash equivalents	**$ 181**	$ 129
Receivables —		
Customer accounts receivable	**111**	117
Affiliated	**55**	50
Other	**116**	98
Materials and supplies	**220**	278
Prepaid income taxes	**25**	50
Other current assets	**37**	36
Total current assets	**745**	758
Property, Plant, and Equipment:		
In service	**13,271**	13,755
Less: Accumulated provision for depreciation	**2,171**	1,910
Plant in service, net of depreciation	**11,100**	11,845
Construction work in progress	**430**	511
Total property, plant, and equipment	**11,530**	12,356
Other Property and Investments:		
Intangible assets, net of amortization of $61 and $47 at December 31, 2018 and December 31, 2017, respectively	**345**	411
Total other property and investments	**345**	411
Deferred Charges and Other Assets:		
Prepaid LTSAs	**98**	118
Accumulated deferred income taxes	**1,186**	925
Income taxes receivable, non-current	**30**	72
Assets held for sale	**576**	—
Other deferred charges and assets	**373**	566
Total deferred charges and other assets	**2,263**	1,681
Total Assets	**$ 14,883**	$ 15,206

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

CONSOLIDATED BALANCE SHEETS
At December 31, 2018 and 2017
Southern Power Company and Subsidiary Companies 2018 Annual Report

Liabilities and Stockholders' Equity	2018	2017
		(in millions)
Current Liabilities:		
Securities due within one year	**$ 599**	$ 770
Notes payable	**100**	105
Accounts payable —		
Affiliated	**92**	102
Other	**77**	103
Accrued taxes	**6**	4
Liabilities held for sale, current	**15**	—
Other current liabilities	**142**	148
Total current liabilities	**1,031**	1,232
Long-Term Debt:		
Senior notes —		
1.95% due 2019	**—**	600
2.375% due 2020	**300**	300
2.50% due 2021	**300**	300
1.00% due 2022	**687**	720
2.75% due 2023	**290**	290
1.85% to 5.25% due 2025-2046	**2,348**	2,374
Other long-term debt —		
Variable rate (3.34% at 12/31/18) due 2020	**525**	525
Unamortized debt premium (discount), net	**(9)**	(10)
Unamortized debt issuance expense	**(23)**	(28)
Total long-term debt	**4,418**	5,071
Deferred Credits and Other Liabilities:		
Accumulated deferred income taxes	**105**	199
Accumulated deferred ITCs	**1,832**	1,884
Other deferred credits and liabilities	**213**	322
Total deferred credits and other liabilities	**2,150**	2,405
Total Liabilities	**7,599**	8,708
Common Stockholder's Equity:		
Common stock, par value $0.01 per share —		
Authorized — 1,000,000 shares		
Outstanding — 1,000 shares	**—**	—
Paid-in capital	**1,600**	3,662
Retained earnings	**1,352**	1,478
Accumulated other comprehensive income (loss)	**16**	(2)
Total common stockholder's equity	**2,968**	5,138
Noncontrolling Interests	**4,316**	1,360
Total Stockholders' Equity	**7,284**	6,498
Total Liabilities and Stockholders' Equity	**$ 14,883**	$ 15,206
Commitments and Contingent Matters (See notes)		

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

CONSOLIDATED STATEMENTS OF STOCKHOLDERS' EQUITY
For the Years Ended December 31, 2018, 2017, and 2016
Southern Power Company and Subsidiary Companies 2018 Annual Report

	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, 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 to parent company, net	—	—	(2)	—	—	(2)	—	(2)
Other comprehensive income	—	—	—	—	(10)	(10)	—	(10)
Cash dividends on common stock	—	—	—	(317)	—	(317)	—	(317)
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**
Net income attributable to Southern Power	—	—	—	**187**	—	**187**	—	**187**
Return of capital to parent	—	—	**(1,650)**	—	—	**(1,650)**	—	**(1,650)**
Capital contributions from parent company	—	—	**2**	—	—	**2**	—	**2**
Other comprehensive income	—	—	—	—	**14**	**14**	—	**14**
Cash dividends on common stock	—	—	—	**(312)**	—	**(312)**	—	**(312)**
Capital contributions from noncontrolling interests	—	—	—	—	—	—	**1,372**	**1,372**
Distributions to noncontrolling interests	—	—	—	—	—	—	**(164)**	**(164)**
Net income attributable to noncontrolling interests	—	—	—	—	—	—	**59**	**59**
Sale of noncontrolling interests[c]	—	—	**(417)**	—	—	**(417)**	**1,690**	**1,273**
Other	—	—	**3**	**(1)**	**4**	**6**	**(1)**	**5**
Balance at December 31, 2018	—	$ —	$ 1,600	$ 1,352	$ 16	$ 2,968	$ 4,316	$ 7,284

(a) Excludes redeemable noncontrolling interests. See Note 7 to the financial statements under "Noncontrolling Interests" for additional information.
(b) In connection with Southern Power 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.
(c) See Note 15 under "Southern Power - Sales of Renewable Facility Interests" for additional information.

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

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 (Southern Company Gas) (a wholly-owned subsidiary of The Southern Company) as of December 31, 2018 and 2017, the related consolidated statements of income, comprehensive income, stockholders' equity, and cash flows for the years ended December 31, 2018 and 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 present fairly, in all material respects, the financial position of Southern Company Gas as of December 31, 2018 and 2017, and the results of its operations and its cash flows for the years ended December 31, 2018 and 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 Southern Company Gas' management. Our responsibility is to express an opinion on Southern Company Gas' financial statements based on our audits. We did not audit the financial statements of Southern Natural Gas Company, L.L.C. (SNG), Southern Company Gas' investment in which is accounted for by the use of the equity method. The accompanying consolidated financial statements of Southern Company Gas include its equity investment in SNG of $1,261 million and $1,262 million as of December 31, 2018 and December 31, 2017, respectively, and its earnings from its equity method investment in SNG of $131 million, $88 million, and $56 million for the years ended December 31, 2018 and 2017 and the six months ended December 31, 2016, respectively. Those statements were audited by other auditors whose reports (which express an unqualified opinion on SNG's financial statements and contain 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 reports 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 Southern Company Gas 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. Southern Company Gas 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 Southern Company Gas' 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 reports of the other auditors provide a reasonable basis for our opinion.

/s/ Deloitte & Touche LLP
Atlanta, Georgia
February 19, 2019

We have served as Southern Company Gas' auditor since 2016.

CONSOLIDATED STATEMENTS OF INCOME
Southern Company Gas and Subsidiary Companies 2018 Annual Report

	Successor			Predecessor
	For the year ended December 31, 2018	For the year ended December 31, 2017	July 1, 2016 through December 31, 2016	January 1, 2016 through June 30, 2016
		(in millions)		*(in millions)*
Operating Revenues:				
Natural gas revenues (includes revenue taxes of $114, $100, $32, and $57 for the periods presented, respectively)	**$ 3,874**	$ 3,787	$ 1,591	$ 1,845
Alternative revenue programs	**(20)**	4	5	(4)
Other revenues	**55**	129	56	64
Total operating revenues	**3,909**	3,920	1,652	1,905
Operating Expenses:				
Cost of natural gas	**1,539**	1,601	613	755
Cost of other sales	**12**	29	10	14
Other operations and maintenance	**981**	945	480	452
Depreciation and amortization	**500**	501	238	206
Taxes other than income taxes	**211**	184	71	99
Goodwill impairment	**42**	—	—	—
Gain on dispositions, net	**(291)**	—	—	—
Merger-related expenses	**—**	—	41	56
Total operating expenses	**2,994**	3,260	1,453	1,582
Operating Income	**915**	660	199	323
Other Income and (Expense):				
Earnings from equity method investments	**148**	106	60	2
Interest expense, net of amounts capitalized	**(228)**	(200)	(81)	(96)
Other income (expense), net	**1**	44	12	3
Total other income and (expense)	**(79)**	(50)	(9)	(91)
Earnings Before Income Taxes	**836**	610	190	232
Income taxes	**464**	367	76	87
Net Income	**372**	243	114	145
Net income attributable to noncontrolling interest	**—**	—	—	14
Net Income Attributable to Southern Company Gas	**$ 372**	$ 243	$ 114	$ 131

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

CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME
Southern Company Gas and Subsidiary Companies 2018 Annual Report

	Successor			Predecessor
	For the year ended December 31, 2018	For the year ended December 31, 2017	July 1, 2016 through December 31, 2016	January 1, 2016 through June 30, 2016
		(in millions)		*(in millions)*
Net Income	**$ 372**	$ 243	$ 114	$ 145
Other comprehensive income (loss):				
Qualifying hedges:				
Changes in fair value, net of tax of $2, $(3), $(1), and $(23), respectively	**5**	(5)	(1)	(41)
Reclassification adjustment for amounts included in net income, net of tax of $(1), $-, $-, and $-, respectively	**(1)**	1	—	1
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 $3, $-, $-, and $4, respectively	**(2)**	—	—	5
Total other comprehensive income (loss)	**2**	(5)	26	(35)
Comprehensive income attributable to noncontrolling interest	**—**	—	—	14
Comprehensive Income Attributable to Southern Company Gas	**$ 374**	$ 238	$ 140	$ 96

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

CONSOLIDATED STATEMENTS OF CASH FLOWS
Southern Company Gas and Subsidiary Companies 2018 Annual Report

	Successor			Predecessor
	For the year ended December 31, 2018	For the year ended December 31, 2017	July 1, 2016 through December 31, 2016	January 1, 2016 through June 30, 2016
		(in millions)		*(in millions)*
Operating Activities:				
Net income	**$ 372**	$ 243	$ 114	$ 145
Adjustments to reconcile net income to net cash provided from (used for) operating activities —				
Depreciation and amortization, total	**500**	501	238	206
Deferred income taxes	**(1)**	236	92	8
Pension and postretirement funding	**—**	—	(125)	—
Hedge settlements	**—**	—	(35)	(26)
Goodwill impairment	**42**	—	—	—
Gain on dispositions, net	**(291)**	—	—	—
Mark-to-market adjustments	**(19)**	(24)	(3)	162
Other, net	**(24)**	(51)	(51)	(57)
Changes in certain current assets and liabilities —				
-Receivables	**(218)**	(94)	(490)	179
-Natural gas for sale, net of temporary LIFO liquidation	**49**	36	(226)	273
-Prepaid income taxes	**(42)**	(39)	(23)	151
-Other current assets	**4**	(24)	(31)	37
-Accounts payable	**372**	(20)	194	43
-Accrued taxes	**10**	110	8	41
-Accrued compensation	**32**	15	(13)	(21)
-Other current liabilities	**(22)**	(8)	24	(30)
Net cash provided from (used for) operating activities	**764**	881	(327)	1,111
Investing Activities:				
Property additions	**(1,388)**	(1,514)	(614)	(509)
Cost of removal, net of salvage	**(96)**	(66)	(40)	(32)
Change in construction payables, net	**(37)**	72	22	(7)
Investment in unconsolidated subsidiaries	**(110)**	(145)	(1,444)	(14)
Returned investment in unconsolidated subsidiaries	**20**	80	5	3
Proceeds from dispositions	**2,609**	—	—	—
Other investing activities	**—**	5	4	3
Net cash provided from (used for) investing activities	**998**	(1,568)	(2,067)	(556)
Financing Activities:				
Increase (decrease) in notes payable, net	**(868)**	262	1,143	(896)
Proceeds —				
First mortgage bonds	**300**	400	—	250
Capital contributions from parent company	**24**	103	1,085	—
Senior notes	**—**	450	900	350
Redemptions and repurchases —				
Gas facility revenue bonds	**(200)**	—	—	—
Medium-term notes	**—**	(22)	—	—
First mortgage bonds	**—**	—	—	(125)
Senior notes	**(155)**	—	(420)	—
Return of capital	**(400)**	—	—	—
Distribution to noncontrolling interest	**—**	—	(15)	(19)
Purchase of 15% noncontrolling interest in SouthStar	**—**	—	(160)	—
Payment of common stock dividends	**(468)**	(443)	(126)	(128)
Other financing activities	**(3)**	(9)	(8)	10
Net cash provided from (used for) financing activities	**(1,770)**	741	2,399	(558)
Net Change in Cash, Cash Equivalents, and Restricted Cash	**(8)**	54	5	(3)
Cash, Cash Equivalents, and Restricted Cash at Beginning of Year	**78**	24	19	22
Cash, Cash Equivalents, and Restricted Cash at End of Year	**$ 70**	$ 78	$ 24	$ 19
Supplemental Cash Flow Information:				
Cash paid (received) during the period for —				
Interest (net of $7, $11, $4, and $3 capitalized, respectively)	**$ 249**	$ 223	$ 135	$ 119
Income taxes, net	**524**	72	23	(100)
Noncash transactions — Accrued property additions at year-end	**97**	135	63	41

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

CONSOLIDATED BALANCE SHEETS
At December 31, 2018 and 2017
Southern Company Gas and Subsidiary Companies 2018 Annual Report

Assets	**2018**	2017
		(in millions)
Current Assets:		
Cash and cash equivalents	**$ 64**	$ 73
Receivables —		
Energy marketing receivable	**801**	607
Customer accounts receivable	**370**	400
Unbilled revenues	**213**	285
Affiliated	**11**	12
Other accounts and notes receivable	**142**	91
Accumulated provision for uncollectible accounts	**(30)**	(28)
Natural gas for sale	**524**	595
Prepaid expenses	**118**	79
Assets from risk management activities, net of collateral	**219**	135
Other regulatory assets, current	**73**	94
Other current assets	**50**	52
Total current assets	**2,555**	2,395
Property, Plant, and Equipment:		
In service	**15,177**	15,833
Less: Accumulated depreciation	**4,400**	4,596
Plant in service, net of depreciation	**10,777**	11,237
Construction work in progress	**580**	491
Total property, plant, and equipment	**11,357**	11,728
Other Property and Investments:		
Goodwill	**5,015**	5,967
Equity investments in unconsolidated subsidiaries	**1,538**	1,477
Other intangible assets, net of amortization of $145 and $120 at December 31, 2018 and December 31, 2017, respectively	**101**	280
Miscellaneous property and investments	**20**	21
Total other property and investments	**6,674**	7,745
Deferred Charges and Other Assets:		
Other regulatory assets, deferred	**669**	901
Other deferred charges and assets	**193**	218
Total deferred charges and other assets	**862**	1,119
Total Assets	**$ 21,448**	$ 22,987

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

CONSOLIDATED BALANCE SHEETS
At December 31, 2018 and 2017
Southern Company Gas and Subsidiary Companies 2018 Annual Report

Liabilities and Stockholder's Equity	**2018**	2017
		(in millions)
Current Liabilities:		
Securities due within one year	**$ 357**	$ 157
Notes payable	**650**	1,518
Energy marketing trade payables	**856**	546
Accounts payable —		
Affiliated	**45**	21
Other	**402**	425
Customer deposits	**133**	128
Accrued taxes —		
Accrued income taxes	**66**	40
Other accrued taxes	**75**	78
Accrued interest	**55**	51
Accrued compensation	**100**	74
Liabilities from risk management activities, net of collateral	**76**	69
Other regulatory liabilities, current	**79**	135
Other current liabilities	**130**	159
Total current liabilities	**3,024**	3,401
Long-term Debt (See accompanying statements)	**5,583**	5,891
Deferred Credits and Other Liabilities:		
Accumulated deferred income taxes	**1,016**	1,089
Deferred credits related to income taxes	**940**	1,063
Employee benefit obligations	**357**	415
Other cost of removal obligations	**1,585**	1,646
Accrued environmental remediation	**268**	342
Other deferred credits and liabilities	**105**	118
Total deferred credits and other liabilities	**4,271**	4,673
Total Liabilities	**12,878**	13,965
Common Stockholder's Equity (See accompanying statements)	**8,570**	9,022
Total Liabilities and Stockholder's Equity	**$ 21,448**	$ 22,987
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, 2018 and 2017
Southern Company Gas and Subsidiary Companies 2018 Annual Report

	2018	2017	2018	2017
	(in millions)		*(percent of total)*	
Long-Term Debt:				
Long-term notes payable —				
3.50% due 2018	**$ —**	$ 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% due 2023	**350**	350		
3.25% to 7.30% due 2025-2047	**3,134**	3,134		
Total long-term notes payable	**4,160**	4,315		
Other long-term debt —				
First mortgage bonds —				
4.70% due 2019	**50**	50		
5.80% due 2023	**50**	50		
2.66% to 6.58% due 2026-2058	**1,225**	925		
Gas facility revenue bonds —				
Variable rate (1.71% at 12/31/17) due 2022	**—**	47		
Variable rate (1.71% at 12/31/17) due 2024-2033	**—**	153		
Total other long-term debt	**1,325**	1,225		
Unamortized fair value adjustment of long-term debt	**474**	525		
Unamortized debt discount	**(19)**	(17)		
Total long-term debt (annual interest requirement — $244 million)	**5,940**	6,048		
Less amount due within one year	**357**	157		
Long-term debt excluding amount due within one year	**5,583**	5,891	**39.4%**	39.5%
Common Stockholder's Equity:				
Common stock — par value $0.01 per share				
Authorized — 100 million shares				
Outstanding — 100 shares				
Paid-in capital	**8,856**	9,214		
Accumulated deficit	**(312)**	(212)		
Accumulated other comprehensive income	**26**	20		
Total common stockholder's equity	**8,570**	9,022	**60.6**	60.5
Total Capitalization	**$ 14,153**	$ 14,913	**100.0%**	100.0%

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

CONSOLIDATED STATEMENTS OF STOCKHOLDERS' EQUITY
Southern Company Gas and Subsidiary Companies 2018 Annual Report

	Southern Company Gas Common Stockholders' Equity								
	Number of Common Shares		Common Stock			Retained Earnings (Accumulated Deficit)	Accumulated Other Comprehensive Income (Loss)	Noncontrolling Interests	Total
	Issued	Treasury	Par Value	Paid-In Capital	Treasury				
	(in thousands)					*(in millions)*			
Predecessor – Balance at December 31, 2015	120,377	217	$ 603	$ 2,099	$ (8)	$ 1,421	$ (186)	$ 46	$3,975
Consolidated net income attributable to Southern Company Gas	—	—	—	—	—	131	—	—	131
Other comprehensive income (loss)	—	—	—	—	—	—	(35)	—	(35)
Stock issued	95	—	—	6	—	—	—	—	6
Stock-based compensation	270	—	2	28	—	—	—	—	30
Cash dividends on common stock	—	—	—	—	—	(128)	—	—	(128)
Reclassification of noncontrolling interest	—	—	—	—	—	—	—	(46)	(46)
Predecessor – Balance at June 30, 2016	120,742	217	605	2,133	(8)	1,424	(221)	—	3,933
Successor – Balance at July 1, 2016	—	—	—	8,001	—	—	—	—	8,001
Consolidated net income attributable to Southern Company Gas	—	—	—	—	—	114	—	—	114
Capital contributions from parent company	—	—	—	1,094	—	—	—	—	1,094
Other comprehensive income (loss)	—	—	—	—	—	—	26	—	26
Cash dividends on common stock	—	—	—	—	—	(126)	—	—	(126)
Successor – Balance at December 31, 2016	—	—	—	9,095	—	(12)	26	—	9,109
Consolidated net income attributable to Southern Company Gas	—	—	—	—	—	243	—	—	243
Capital contributions from parent company, net	—	—	—	117	—	—	—	—	117
Other comprehensive income (loss)	—	—	—	—	—	—	(5)	—	(5)
Cash dividends on common stock	—	—	—	—	—	(443)	—	—	(443)
Other	—	—	—	2	—	—	(1)	—	1
Successor – Balance at December 31, 2017	—	—	—	**9,214**	—	**(212)**	**20**	—	**9,022**
Consolidated net income attributable to Southern Company Gas	—	—	—	—	—	**372**	—	—	**372**
Return of capital to parent	—	—	—	**(400)**	—	—	—	—	**(400)**
Capital contributions from parent company	—	—	—	**42**	—	—	—	—	**42**
Other comprehensive income (loss)	—	—	—	—	—	—	**2**	—	**2**
Cash dividends on common stock	—	—	—	—	—	**(468)**	—	—	**(468)**
Other	—	—	—	—	—	**(4)**	**4**	—	—
Successor – Balance at December 31, 2018	—	—	**$ —**	**$ 8,856**	**$ —**	**$ (312)**	**$ 26**	**$ —**	**$8,570**

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

COMBINED NOTES TO FINANCIAL STATEMENTS
Southern Company and Subsidiary Companies 2018 Annual Report

Notes to the Financial Statements
for
The Southern Company and Subsidiary Companies
Alabama Power Company
Georgia Power Company
Mississippi Power Company
Southern Power Company and Subsidiary Companies
Southern Company Gas and Subsidiary Companies

Index to the Combined Notes to Financial Statements

Note		Page
1	Summary of Significant Accounting Policies	II-265
2	Regulatory Matters	II-287
3	Contingencies	II-314
4	Revenue from Contracts with Customers	II-319
5	Property, Plant, and Equipment	II-323
6	Asset Retirement Obligations	II-328
7	Consolidated Entities and Equity Method Investments	II-332
8	Financing	II-337
9	Commitments	II-350
10	Income Taxes	II-353
11	Retirement Benefits	II-364
12	Stock Compensation	II-394
13	Fair Value Measurements	II-399
14	Derivatives	II-407
15	Acquisitions and Dispositions	II-419
16	Segment and Related Information	II-425
17	Quarterly Financial Information (Unaudited)	II-430

Index to Applicable Notes to Financial Statements by Registrant

The following notes to the financial statements are a combined presentation. The list below indicates the registrants to which each note applies.

Registrant	Applicable Notes
Southern Company	1, 2, 3, 4, 5, 6, 7, 8, 9, 10, 11, 12, 13, 14, 15, 16, 17
Alabama Power	1, 2, 3, 4, 5, 6, 7, 8, 9, 10, 11, 12, 13, 14, 17
Georgia Power	1, 2, 3, 4, 5, 6, 7, 8, 9, 10, 11, 12, 13, 14, 17
Mississippi Power	1, 2, 3, 4, 5, 6, 8, 9, 10, 11, 12, 13, 14, 17
Southern Power	1, 3, 4, 5, 6, 7, 8, 9, 10, 11, 12, 13, 14, 15, 17
Southern Company Gas	1, 2, 3, 4, 5, 6, 7, 8, 9, 10, 11, 12, 13, 14, 15, 16, 17

COMBINED NOTES TO FINANCIAL STATEMENTS (continued)
Southern Company and Subsidiary Companies 2018 Annual Report

1. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

General

Southern Company is the parent company of the traditional electric operating companies, Southern Power, Southern Company Gas (as of July 1, 2016), SCS, Southern Linc, 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 (through December 31, 2018), and Mississippi Power – are vertically integrated utilities providing electric service in four Southeastern states. On January 1, 2019, Southern Company completed the sale of Gulf Power to NextEra Energy. 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. On May 22, 2018, Southern Power sold a noncontrolling 33% equity interest in SP Solar, a limited partnership indirectly owning substantially all of Southern Power's solar facilities, and, on December 11, 2018, Southern Power sold a noncontrolling tax equity interest in SP Wind, a holding company owning a portfolio of eight operating wind facilities. On November 5, 2018, Southern Power entered into an agreement to sell all of its equity interests in Plant Mankato (including the 385-MW expansion currently under construction). On December 4, 2018, Southern Power sold all of its equity interests in Plant Oleander and Plant Stanton Unit A (together, the Florida Plants) to NextEra Energy. Southern Company Gas distributes natural gas through natural gas distribution utilities and is involved in several other complementary businesses including gas pipeline investments, wholesale gas services, and gas marketing services. In July 2018, Southern Company Gas completed sales of three of its natural gas distribution utilities (Elizabethtown Gas (New Jersey), Florida City Gas, and Elkton Gas (Maryland)). The remaining natural gas distribution utilities include Nicor Gas (Illinois), Atlanta Gas Light (Georgia), Virginia Natural Gas, and Chattanooga Gas (Tennessee). In June 2018, Southern Company Gas also completed the sale of Pivotal Home Solutions, which provided home equipment protection products and services. 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 Alabama Power's Plant Farley and Georgia Power's Plant Hatch and Plant Vogtle Units 1 and 2, 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 energy solutions, including distributed energy infrastructure, energy efficiency products and services, and utility infrastructure services, to customers. See Note 15 for additional information regarding disposition activities.

The registrants' financial statements reflect investments in subsidiaries on a consolidated basis. Intercompany transactions have been eliminated in consolidation. The equity method is used for investments in entities in which a registrant has significant influence but does not control and for VIEs where a registrant has an equity investment but is not the primary beneficiary. Southern Power has consolidated renewable generation projects that are partially funded by tax equity investors. The related contractual provisions represent profit-sharing arrangements because the allocations of cash distributions and tax benefits are not based on fixed ownership percentages. Therefore, the noncontrolling interest is accounted for under a balance sheet approach utilizing the HLBV method. The HLBV method calculates each partner's share of income based on the change in net equity the partner can legally claim in a HLBV at the end of the period compared to the beginning of the period. See Note 7 for additional information.

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 respective financial statements of the registrants 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 the registrants' results of operations, financial position, or cash flows. In addition, Southern Company Gas has recast its reportable segments. See Note 16 under "Southern Company Gas" for additional information.

At December 31, 2018, Southern Company and Southern Power each had assets and liabilities held for sale on their balance sheets. Unless otherwise noted, the disclosures herein related to specific asset and liability balances at December 31, 2018 exclude assets and liabilities held for sale. See Note 15 under "Assets Held for Sale" for additional information including Southern Company's and Southern Power's major classes of assets and liabilities classified as held for sale.

Southern Company Gas

Pursuant to the Merger, Southern Company pushed down the application of the acquisition method of accounting to the financial statements of Southern Company Gas such that the assets and liabilities are recorded at their respective fair values, and goodwill was established for the excess of the purchase price over the fair value of net identifiable assets. Accordingly, the financial statements of Southern Company Gas 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 Southern Company Gas' financial statements and the combined 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 Southern Company Gas' financial statements has been modified or reclassified to conform to the presentation used by Southern Company. Changes to Southern Company Gas' 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 Southern Company Gas' 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.

Recently Adopted 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 standard is to recognize revenue to depict the transfer of goods or services to customers at the amount expected to be collected. ASC 606 became effective on January 1, 2018 and the registrants adopted it using the modified retrospective method applied to open contracts and only to the version of contracts in effect as of January 1, 2018. In accordance with the modified retrospective method, the registrants' previously issued financial statements have not been restated to comply with ASC 606 and the registrants did not have a cumulative-effect adjustment to retained earnings. The adoption of ASC 606 had no significant impact on the timing of revenue recognition compared to previously reported results; however, it requires enhanced disclosures regarding the nature, amount, timing, and uncertainty of revenue and the related cash flows arising from contracts with customers, which are included herein and in Note 4.

ASC 606 provided additional clarity on financial statement presentation that resulted in reclassifications into other revenues and other operations and maintenance from other income/(expense), net at Alabama Power and Georgia Power primarily related to certain unregulated sales of products and services. In addition, contract assets related to certain fixed retail revenues at Georgia Power and Southern Company's unregulated distributed generation business have been reclassified from unbilled revenue in accordance with the guidance in ASC 606. These reclassifications did not affect the timing or amount of revenues recognized or cash flows. ASC 606 also provided additional guidance on revenue recognized over time, resulting in a change in the timing of revenue recognized from guaranteed and fixed billing arrangements at Southern Company Gas.

COMBINED NOTES TO FINANCIAL STATEMENTS (continued)
Southern Company and Subsidiary Companies 2018 Annual Report

The specific impacts of applying ASC 606 to revenues from contracts with customers on the financial statements of Southern Company, Alabama Power, Georgia Power, and Southern Company Gas compared to previously recognized guidance is shown below.

	For the Year Ended December 31, 2018		
Statements of Income	**As Reported**	**Balances Without Adoption of ASC 606**	**Effect of Change**
		(in millions)	
Southern Company			
Natural gas revenues	$ 3,854	$ 3,852	$ 2
Other revenues	1,239	1,234	5
Other operations and maintenance	5,889	5,830	59
Operating Income	4,191	4,243	(52)
Other income (expense), net	114	60	54
Earnings Before Income Taxes	2,749	2,747	2
Income taxes	449	448	1
Consolidated Net Income	2,300	2,299	1
Consolidated Net Income Attributable to Southern Company	2,226	2,225	1
Alabama Power			
Other revenues	$ 267	$ 230	$ 37
Other operations and maintenance	1,669	1,625	44
Taxes other than income taxes	389	388	1
Operating Income	1,477	1,485	(8)
Other income (expense), net	20	12	8
Georgia Power			
Other revenues	$ 481	$ 387	$ 94
Other operations and maintenance	1,860	1,772	88
Operating Income	1,289	1,283	6
Other income (expense), net	115	121	(6)
Southern Company Gas			
Natural gas revenues	$ 3,874	$ 3,872	$ 2
Operating Income	915	913	2
Earnings Before Income Taxes	836	834	2
Income taxes	464	463	1
Net Income	372	371	1

COMBINED NOTES TO FINANCIAL STATEMENTS (continued)
Southern Company and Subsidiary Companies 2018 Annual Report

Statements of Cash Flows	For the Year Ended December 31, 2018		
	As Reported	Balances Without Adoption of ASC 606	Effect of Change
		(in millions)	
Southern Company			
Consolidated net income	$ 2,300	$ 2,299	$ 1
Changes in certain current assets and liabilities:			
Receivables	(426)	(472)	46
Other current assets	(127)	(81)	(46)
Accrued taxes	267	268	(1)
Other current liabilities	63	61	2
Georgia Power			
Changes in certain current assets and liabilities:			
Receivables	$ 8	$ 1	$ 7
Other current assets	(43)	(36)	(7)
Southern Company Gas			
Net income	$ 372	$ 371	$ 1
Changes in certain current assets and liabilities:			
Accrued taxes	10	11	(1)
Other current liabilities	(22)	(24)	2

Balance Sheets	At December 31, 2018		
	As Reported	Balances Without Adoption of ASC 606	Effect of Change
		(in millions)	
Southern Company			
Unbilled revenues	$ 654	$ 728	$ (74)
Other accounts and notes receivable	813	814	(1)
Other current assets	162	87	75
Accrued taxes	656	655	1
Other current liabilities	852	854	(2)
Total Stockholders' Equity	29,039	29,038	1
Georgia Power			
Unbilled revenues	$ 208	$ 243	$ (35)
Other accounts and notes receivable	80	81	(1)
Other current assets	70	34	36
Southern Company Gas			
Accrued income taxes	$ 66	$ 65	$ 1
Other current liabilities	130	132	(2)
Common Stockholder's Equity	8,570	8,569	1

Other

In 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 statements of cash flows. In addition, the net change in cash and cash equivalents during the period includes amounts generally described as restricted cash or restricted cash equivalents. The registrants adopted ASU 2016-18 retrospectively effective January 1, 2018. Southern Company, Southern Power, and Southern Company Gas have restated prior periods in the statements of cash flows by immaterial amounts. The change in restricted cash in the statements of cash flows was previously disclosed in operating activities for Southern Company and Southern Company Gas and in investing activities for Southern Company and Southern Power. See "Restricted Cash" herein for additional information.

In January 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 registrants adopted ASU 2017-04 effective January 1, 2018 with no impact on their respective financial statements.

In March 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 statements of income outside of income from operations. Additionally, only the service cost component is eligible for capitalization, when applicable. The registrants adopted ASU 2017-07 effective January 1, 2018 with no material impact on their respective financial statements. ASU 2017-07 has been applied retrospectively, with the service cost component of net periodic benefit costs included in operations and maintenance expenses and all other components of net periodic benefit costs included in other income (expense), net in the statements of income for all periods presented for Southern Company, the traditional electric operating companies, and Southern Company Gas. The impacted registrants used the practical expedient provided by ASU 2017-07, which permits an employer to use the amounts disclosed in its retirement benefits note for prior comparative periods as the estimation basis for applying the retrospective presentation requirements to those periods. The amounts of the other components of net periodic benefit costs reclassified for the prior periods are presented in Note 11. The presentation changes resulted in a decrease in operating income and an increase in other income for the years ended December 31, 2017 and 2016 for each of the impacted registrants. Since Southern Power did not participate in the qualified pension and postretirement benefit plans until December 2017, no retrospective presentation of Southern Power's net periodic benefit costs is required. The requirement to limit capitalization to the service cost component of net periodic benefit costs has been applied on a prospective basis from the date of adoption for all registrants.

In August 2017, the FASB issued ASU No. 2017-12, *Derivatives and Hedging (Topic 815): Targeted Improvements to Accounting for Hedging Activities* (ASU 2017-12). 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 registrants adopted ASU 2017-12 effective January 1, 2018 with no material impact on their respective financial statements. See Note 14 for disclosures required by ASU 2017-12.

On February 14, 2018, the FASB issued ASU No. 2018-02, *Income Statement – Reporting Comprehensive Income (Topic 220): Reclassification of Certain Tax Effects from Accumulated Other Comprehensive Income* (ASU 2018-02) to address the application of ASC 740, *Income Taxes* (ASC 740) to certain provisions of the Tax Reform Legislation. ASU 2018-02 specifically addresses the ASC 740 requirement that the effect of a change in tax laws or rates on deferred tax assets and liabilities be included in income from continuing operations, even when the tax effects were initially recognized directly in OCI at the previous rate, which strands the income tax rate differential in accumulated OCI. The amendments in ASU 2018-02 allow a reclassification from accumulated OCI to retained earnings for stranded tax effects resulting from the Tax Reform Legislation. The registrants adopted ASU 2018-02 effective January 1, 2018 with no material impact on their respective financial statements.

On August 28, 2018, the FASB issued ASU No. 2018-14, *Compensation – Retirement Benefits – Defined Benefit Plans – General (Topic 715-20): Disclosure Framework – Changes to the Disclosure Requirements for Defined Benefit Plans* (ASU 2018-14). ASU 2018-14 amends ASC 715 to add, remove, and clarify disclosure requirements related to defined benefit pension and other

postretirement plans. The registrants adopted ASU 2018-14 effective December 31, 2018 with no material impact on their respective financial statements. See Note 11 for disclosures required by ASU 2018-14.

Affiliate Transactions

The traditional electric operating companies, Southern Power, and Southern Company Gas have agreements with SCS under which certain of the following services are rendered to them at direct or allocated cost: general executive and advisory, general and design engineering, operations, purchasing, accounting, finance, treasury, legal, tax, information technology, marketing, auditing, insurance and pension administration, human resources, systems and procedures, digital wireless communications, cellular tower space, and other services with respect to business and operations, construction management, and power pool transactions. These costs are primarily included in other operations and maintenance expenses or capitalized to property, plant, and equipment. Costs for these services from SCS in 2018, 2017, and 2016 were as follows:

	Alabama Power	Georgia Power	Mississippi Power	Southern Power[a]	Southern Company Gas[b]
			(in millions)		
2018	$ 508	$ 653	$ 104	$ 98	$ 194
2017	479	625	140	218	63
2016	460	606	231	193	17

(a) Prior to December 2017, Southern Power had no employees but was billed for employee-related costs from SCS.

(b) Southern Company Gas' 2016 costs represent services provided subsequent to the Merger.

Alabama Power and Georgia Power also have agreements with Southern Nuclear under which Southern Nuclear renders the following nuclear-related services 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; other services with respect to business and operations; and, for Georgia Power, construction management. These costs are primarily included in other operations and maintenance expenses or capitalized to property, plant, and equipment. Costs for these services in 2018, 2017, and 2016 amounted to $247 million, $248 million, and $249 million, respectively, for Alabama Power and $780 million, $675 million, and $666 million, respectively, for Georgia Power. See Note 2 under "Georgia Power – Nuclear Construction" for additional information regarding Southern Nuclear's construction management of Plant Vogtle Units 3 and 4 for Georgia Power.

Cost allocation methodologies used by SCS and Southern Nuclear 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.

Alabama Power's and Georgia Power's total power purchased from affiliates through the power pool is included in purchased power, affiliates on their respective statements of income. Mississippi Power's and Southern Power's total power purchased from affiliates through the power pool is included in purchased power on their respective statements of income and was as follows:

	Mississippi Power	Southern Power
	(in millions)	
2018	$ 15	$ 41
2017	16	27
2016	29	21

SCS, as agent for Alabama Power, Georgia Power, Southern Power, and Southern Company Gas, has long-term interstate natural gas transportation agreements with SNG. The interstate transportation service provided to Alabama Power, Georgia Power, Southern Power, and Southern Company Gas 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. See Notes 7 and 15 under "Southern Company Gas – Equity Method Investments – SNG" and "Southern Company Gas – Investment in SNG," respectively, for additional information. Transportation costs under these agreements in 2018, 2017, and 2016 were as follows:

	Alabama Power	Georgia Power	Southern Power	Southern Company Gas
		(in millions)		
2018	$ 8	$ 101	$ 25	$ 32
2017	9	102	25	32
2016(*)	2	35	7	15

(*) Represents costs incurred for the period subsequent to Southern Company Gas' investment in SNG.

On November 16, 2018, SNG completed its purchase of Georgia Power's natural gas lateral pipeline serving Plant McDonough Units 4 through 6 at net book value, as approved by the Georgia PSC on January 16, 2018. SNG expects to pay $142 million to Georgia Power in the first quarter 2020. During the interim period, Georgia Power will receive a discounted shipping rate to reflect the delayed consideration. Southern Company Gas' portion of the expected capital expenditures for the purchase of this pipeline and additional construction is $122 million.

SCS, as agent for the traditional electric operating companies and Southern Power, has agreements with certain subsidiaries of Southern Company Gas to purchase natural gas. Natural gas purchases made under these agreements were immaterial for Alabama Power and Mississippi Power and as follows for Georgia Power and Southern Power in 2018, 2017, and 2016:

	Georgia Power	Southern Power
	(in millions)	
2018	$ 21	$ 119
2017	22	119
2016(*)	10	17

(*) Represents costs incurred for the period subsequent to Southern Company's acquisition of Southern Company Gas.

Alabama Power and Mississippi Power jointly own Plant Greene County. The companies have an agreement under which Alabama Power operates Plant Greene County and Mississippi Power reimburses Alabama Power for its proportionate share of non-fuel expenses, which totaled $8 million, $9 million, and $13 million in 2018, 2017, and 2016, respectively. Mississippi Power also reimburses Alabama Power for any direct fuel purchases delivered from one of Alabama Power's transfer facilities. There were no such fuel purchases in 2018, 2017, and 2016. See Note 5 under "Joint Ownership Agreements" for additional information.

Alabama Power has an agreement with Gulf 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 Autauga County, Alabama. Under a related tariff, Alabama Power received $11 million in 2018, $11 million in 2017, and $12 million in 2016. See Note 15 under "Southern Company's Sale of Gulf Power" for information regarding the sale of Gulf Power.

Alabama Power has agreements with PowerSecure for services related to utility infrastructure construction, distributed energy, and energy efficiency projects. Costs for these services amounted to approximately $24 million in 2018 and $11 million in 2017 and were immaterial in 2016.

See Note 7 under "SEGCO" for information regarding Alabama Power's and Georgia Power's equity method investment in SEGCO and related affiliate purchased power costs, as well as Alabama Power's gas pipeline ownership agreement with SEGCO.

Georgia Power has entered into several PPAs with Southern Power for capacity and energy. Total expenses associated with these PPAs were $216 million, $235 million, and $265 million in 2018, 2017, and 2016, respectively. See Note 8 under "Long-term Debt – Capital Leases – Georgia Power" and Note 9 under "Fuel and Power Purchase Agreements – Affiliate" for additional information.

Georgia Power has a joint ownership agreement with Gulf Power under which Gulf Power owns a 25% portion of Plant Scherer Unit 3. Under this agreement, Georgia Power operates Plant Scherer Unit 3 and Gulf Power reimburses Georgia Power for its 25% proportionate share of the related non-fuel expenses, which were $8 million, $11 million, and $8 million in 2018, 2017, and 2016, respectively. See Note 5 under "Joint Ownership Agreements" and Note 15 under "Southern Company's Sale of Gulf Power" for additional information.

Mississippi Power has an agreement with Gulf Power under which Gulf Power owns a portion of Plant Daniel. Mississippi Power operates Plant Daniel and Gulf Power reimburses Mississippi Power for its proportionate share of all associated expenditures and costs, which totaled $31 million, $31 million, and $26 million in 2018, 2017, and 2016, respectively. See Note 5 under "Joint Ownership Agreements" and Note 15 under "Southern Company's Sale of Gulf Power" for additional information.

In 2014, prior to Southern Company's 2016 acquisition of PowerSecure, Georgia Power 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 $32 million made by Georgia Power to PowerSecure under the agreements since Southern Company's acquisition of PowerSecure are included in plant in service at December 31, 2018.

Southern Power's total revenues from all PPAs with Georgia Power, included in wholesale revenue affiliates on Southern Power's consolidated statements of income, were $215 million, $233 million, and $258 million for 2018, 2017, and 2016, respectively. Included within these revenues were affiliate PPAs accounted for as operating leases, which totaled $65 million, $81 million, and $109 million for 2018, 2017, and 2016, respectively.

Southern Power has several agreements with SCS for transmission services. Transmission services purchased by Southern Power from SCS totaled $12 million, $13 million, and $11 million for 2018, 2017, and 2016, respectively, and were charged to other operations and maintenance in Southern Power's consolidated statements of income. All charges were billed to Southern Power based on the Southern Company Open Access Transmission Tariff as filed with the FERC.

The traditional electric operating companies 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 9 under "Fuel and Power Purchase Agreements" for additional information. Southern Power 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. See "Revenues – Southern Power" herein for additional information.

The traditional electric operating companies, Southern Power, and Southern Company Gas provide incidental services to and receive such services from other Southern Company subsidiaries which are generally minor in duration and amount. Except as described herein, the traditional electric operating companies, Southern Power, and Southern Company Gas neither provided nor received any material services to or from affiliates in 2018, 2017, or 2016.

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.

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 AOCI related regulatory assets and liabilities that are not specifically recoverable through regulated rates. In addition, the traditional electric operating company or natural gas distribution utility would be required to determine if any impairment to other assets, including plant, exists and write down the assets, if impaired, to their fair values. All regulatory assets and liabilities are to be reflected in rates. See Note 2 for additional information including details of regulatory assets and liabilities reflected in the balance sheets for Southern Company, the traditional electric operating companies, and Southern Company Gas.

Revenues

The registrants generate revenues from a variety of sources which are accounted for under various revenue accounting guidance, including ASC 606, lease, derivative, and regulatory accounting. Other than the timing of recognition of guaranteed and fixed billing arrangements at Southern Company Gas, the adoption of ASC 606 had no impact on the timing or amount of revenue recognized under previous guidance. See "Recently Adopted Accounting Standards – Revenue" herein and Note 4 for information regarding the registrants' adoption of ASC 606 and related disclosures.

Traditional Electric Operating Companies

The majority of the revenues of the traditional electric operating companies are generated from contracts with retail electric customers. Retail revenues recognized under ASC 606 are consistent with prior revenue recognition policies. These revenues, generated from the integrated service to deliver electricity when and if called upon by the customer, are recognized as a single performance obligation satisfied over time, at a tariff rate, and as electricity is delivered to the customer during the month. Unbilled revenues related to retail sales are accrued at the end of each fiscal period. Retail rates may 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 from or returned to customers, respectively, through adjustments to the billing factors. See Note 2 for additional information regarding regulatory matters of the traditional electric operating companies.

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 generally recognized as services are provided. The accounting for these revenues under ASC 606 is consistent with prior revenue recognition policies. The contracts for capacity and energy in a wholesale PPA have multiple performance obligations where the contract's total transaction price is allocated to each performance obligation based on the standalone selling price. The standalone selling price is primarily determined by the price charged to customers for the specific goods or services transferred with the performance obligations. Generally, the traditional electric operating companies recognize revenue as the performance obligations are satisfied over time as electricity is delivered to the customer or as generation capacity is available to the customer.

For both retail and wholesale revenues, the traditional electric operating companies generally have a right to consideration in an amount that corresponds directly with the value to the customer of the entity's performance completed to date and may recognize revenue in the amount to which the entity has a right to invoice and has elected to recognize revenue for its sales of electricity and capacity using the invoice practical expedient. In addition, payment for goods and services rendered is typically due in the subsequent month following satisfaction of the registrants' performance obligation.

Southern Power

Southern Power sells capacity and energy at rates specified under contractual terms in long-term PPAs. These PPAs are 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. Energy revenues are recognized in the period the energy is delivered.

Southern Power's non-lease contracts commonly include capacity and energy which are considered separate performance obligations. In these contracts, the total transaction price is allocated to each performance obligation based on the standalone selling price. The standalone selling price is primarily determined by the price charged to customers for the specific goods or services transferred with the performance obligations. Generally, Southern Power recognizes revenue as the performance obligations are satisfied over time, as electricity is delivered to the customer or as generation capacity is made available to the customer. The timing of revenue recognition was not affected by the adoption of ASC 606.

Southern Power generally has a right to consideration in an amount that corresponds directly with the value to the customer of the entity's performance completed to date and may recognize revenue in the amount to which the entity has a right to invoice. In addition, payment for goods and services rendered is typically due in the subsequent month following satisfaction of Southern Power's performance obligation.

When multiple contracts exist with the same counterparty, the revenues from each contract are accounted for as separate arrangements.

Southern Power 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 and losses on such contracts are recorded in wholesale revenues. See Note 14 and "Financial Instruments" herein for additional information.

Southern Company Gas

Gas Distribution Operations

Southern Company Gas records revenues when goods or services are provided to customers. Those revenues are based on rates approved by the state regulatory agencies of the natural gas distribution utilities. 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. 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.

The majority of the revenues of Southern Company Gas are generated from contracts with natural gas distribution customers. Revenues from this integrated service to deliver gas when and if called upon by the customer is recognized as a single performance obligation satisfied over time and is recognized at a tariff rate as gas is delivered to the customer during the month.

The standalone selling price is primarily determined by the price charged to customers for the specific goods or services transferred with the performance obligations. Generally, Southern Company Gas recognizes revenue as the performance obligations are satisfied over time as natural gas is delivered to the customer. The performance obligations related to wholesale gas services are satisfied, and revenue is recognized, at a point in time when natural gas is delivered to the customer.

Southern Company Gas generally has a right to consideration in an amount that corresponds directly with the value to the customer of the entity's performance completed to date and may recognize revenue in the amount to which the entity has a right to invoice and has elected to recognize revenue for its sales of natural gas using the invoice practical expedient. In addition, payment for goods and services rendered is typically due in the subsequent month following satisfaction of Southern Company Gas' performance obligation.

With the exception of Atlanta Gas Light, the natural gas distribution utilities 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 through 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, as 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, Chattanooga Gas, and, prior to its sale, Elizabethtown 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, prior to its sale, 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.

Wholesale Gas Services

Southern Company Gas 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. Southern Company Gas 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.

Gas Marketing Services

Southern Company Gas 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. Southern Company Gas 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.

Southern Company Gas recognizes revenues on 12-month utility-bill management contracts as the lesser of cumulative earned or cumulative billed amounts. Prior to the sale of Pivotal Home Solutions, revenues for warranty and repair contracts were recognized on a straight-line basis over the contract term while revenues for maintenance services were recognized at the time such services were performed. See Note 15 under "Southern Company Gas – Sale of Pivotal Home Solutions" for additional information.

Concentration of Revenue

Southern Company, Alabama Power, Georgia Power, Mississippi Power (with the exception of its cost-based MRA electric tariffs described below), and Southern Company Gas each have a diversified base of customers and no single customer or industry comprises 10% or more of each company's revenues.

Mississippi Power 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 17.3% of Mississippi Power's total operating revenues in 2018 and are generally subject to 10-year rolling 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.

Significant portions of Southern Power's revenues have been derived from certain customers pursuant to PPAs. The following table shows the percentage of total revenues for Southern Power's top three customers for each of the years presented:

	2018	2017	2016
Georgia Power	**9.8%**	11.3%	16.5%
Duke Energy Corporation	**6.8%**	6.7%	7.8%
Southern California Edison	**6.2%**	N/A	N/A
Morgan Stanley Capital Group	**N/A**	4.5%	N/A
San Diego Gas & Electric Company	**N/A**	N/A	5.7%

On January 29, 2019, Pacific Gas & Electric Company (PG&E) filed petitions to reorganize under Chapter 11 of the U.S. Bankruptcy Code. Southern Power, together with its noncontrolling partners, owns four solar facilities where PG&E is the energy off-taker for approximately 207 MWs of capacity under long-term PPAs. PG&E is also the transmission provider for these facilities and two of Southern Power's other solar facilities. Southern Power has evaluated the recoverability of its investments in these solar facilities under various scenarios, including selling the related energy into the competitive markets, and has concluded they are not impaired. At December 31, 2018, Southern Power had outstanding accounts receivables due from PG&E of $1 million related to the PPAs and $36 million related to the transmission interconnections (of which $17 million is classified in other deferred charges and assets). Southern Power does not expect a material impact to its financial statements if, as a result of the bankruptcy proceedings, PG&E does not perform in accordance with the PPAs or the terms of the PPAs are renegotiated; however, the ultimate outcome of this matter cannot be determined at this time.

Fuel Costs

Fuel costs for the traditional electric operating companies and Southern Power 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. For Alabama Power and Georgia Power, fuel expense also includes the amortization of the cost of nuclear fuel. For the traditional electric operating companies, fuel costs also include gains and/or losses from fuel-hedging programs as approved by their respective state PSCs.

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.

Southern Company Gas' gas marketing services' customers are charged for actual or estimated natural gas consumed. Within cost of natural gas, Southern Company Gas also includes costs of lost and unaccounted for gas, adjustments to reduce the value of inventories to market value, and gains and losses associated with certain derivatives.

Income Taxes

The registrants use the liability method of accounting for deferred income taxes and provide deferred income taxes for all significant income tax temporary differences. 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 related to the construction of renewable facilities are eligible for federal ITCs. Southern Power 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. Southern Power applies the deferred method to ITCs. 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. 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. State ITCs are recognized as an income tax benefit in the period in which the credits are generated. In addition, certain projects are eligible for federal and state PTCs, which are recognized as an income tax benefit 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 2018 and will be carried forward and utilized in future years. In addition, Southern Company is expected to have various state net operating loss (NOL) carryforwards for certain of its subsidiaries, which would result in income tax benefits in the future, if utilized. See Note 10 under "Current and Deferred Income Taxes – Tax Credit Carryforwards" and " – Net Operating Loss Carryforwards" for additional information.

The registrants recognize tax positions that are "more likely than not" of being sustained upon examination by the appropriate taxing authorities. See Note 10 under "Unrecognized Tax Benefits" for additional information.

Other Taxes

Taxes imposed on and collected from customers on behalf of governmental agencies are presented net on the registrants' statements of income and are excluded from the transaction price in determining the revenue related to contracts with a customer accounted for under ASC 606.

Southern Company Gas is taxed on its gas revenues by various governmental authorities, but is allowed to recover these taxes from its customers. Revenue taxes imposed on the natural gas distribution utilities are recorded at the amount charged to customers, which may include a small administrative fee, as operating revenues, and the related taxes imposed on Southern Company Gas are recorded as operating expenses on the statements of income. Revenue taxes included in operating expenses were $111 million and $98 million for the successor years ended December 31, 2018 and 2017, respectively, $31 million for the successor period of July 1, 2016 through December 31, 2016, and $56 million for the predecessor period of January 1, 2016 through June 30, 2016.

Allowance for Funds Used During Construction and Interest Capitalized

The traditional electric operating companies and certain of the natural gas distribution utilities (Atlanta Gas Light, Chattanooga Gas, and Nicor Gas) 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 asset through a higher rate base and higher depreciation. The equity component of AFUDC is not taxable.

Interest related to the construction of new facilities at Southern Power and new facilities not included in the traditional electric operating companies' and Southern Company Gas' regulated rates is capitalized in accordance with standard interest capitalization requirements.

Total AFUDC and interest capitalized for the registrants in 2018, 2017, and 2016 was as follows:

	Southern Company	Alabama Power	Georgia Power[a]	Mississippi Power[b]	Southern Power
			(in millions)		
2018	$ 210	$ 84	$ 94	$ —	$ 17
2017	249	54	63	72	11
2016	327	39	68	124	44

(a) See Note 2 under "Georgia Power – Nuclear Construction" for information on the inclusion of a portion of construction costs related to Plant Vogtle Units 3 and 4 in Georgia Power's rate base.

(b) Mississippi Power's decrease in 2017 resulted from the Kemper IGCC project suspension in June 2017.

	Successor			Predecessor
	Year Ended December 31, 2018	Year Ended December 31, 2017	July 1, 2016 through December 31, 2016	January 1, 2016 through June 30, 2016
	(in millions)			*(in millions)*
Southern Company Gas	$ 14	$ 19	$ 6	$ 4

The average AFUDC composite rates for 2018, 2017, and 2016 for the traditional electric operating companies and Southern Company Gas were as follows:

	Alabama Power	Georgia Power	Mississippi Power
2018	8.3%	7.3%	3.3%
2017	8.3%	5.6%	6.7%
2016	8.2%	6.9%	6.5%

	Successor			Predecessor
	Year Ended December 31, 2018	Year Ended December 31, 2017	July 1, 2016 through December 31, 2016	January 1, 2016 through June 30, 2016
Southern Company Gas:				
Atlanta Gas Light[a]	7.9%	8.1%	4.1%	4.1%
Chattanooga Gas[a]	7.4%	7.4%	3.7%	3.7%
Nicor Gas[b]	2.1%	1.2%	1.5%	1.5%

(a) Fixed rates authorized by the Georgia PSC and Tennessee Public Utilities Commission for Atlanta Gas Light and Chattanooga Gas, respectively.

(b) Variable rate determined by the FERC method of AFUDC accounting.

Impairment of Long-Lived Assets

The registrants evaluate long-lived assets and finite-lived intangible 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, a sales transaction price that is less than the asset group's carrying value, or an estimate of undiscounted future cash flows attributable to the asset group, 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 15 under "Southern Power" for information regarding impairment charges recorded in 2018. Also see "Revenues" and "Leveraged Leases" herein and Note 3 under "Other Matters – Southern Company Gas" for additional information.

Goodwill and Other Intangible Assets and Liabilities

Southern Power's intangible assets consist primarily of certain PPAs acquired, which are amortized over the term of the respective PPA. Southern Company Gas' goodwill and other intangible assets and liabilities primarily relate to its 2016 acquisition by Southern Company. In addition to these items, Southern Company's goodwill and other intangible assets also relate to its 2016 acquisition of PowerSecure. See Note 15 under "Southern Company Merger with Southern Company Gas" and "Southern Company Acquisition of PowerSecure" for additional information.

Goodwill is not amortized, but is subject to an annual impairment test during the fourth quarter of each year, or more frequently if impairment indicators arise. Southern Company Gas recorded a goodwill impairment charge in the first quarter 2018 related to its disposition of Pivotal Home Solutions. Southern Company and Southern Company Gas each evaluated its goodwill in the fourth quarter 2018 and determined no additional impairment was required. The following table presents 2018 changes in goodwill balances for Southern Company and Southern Company Gas:

			Southern Company Gas	
	Southern Company		Gas Distribution Operations	Gas Marketing Services
		(in millions)		
Balance at December 31, 2017	$	6,268	$ 4,702	$ 1,265
Impairment[a]		(42)	—	(42)
Dispositions[b]		(910)	(668)	(242)
Balance at December 31, 2018	$	5,315 [c]	$ 4,034	$ 981

(a) On April 11, 2018, Southern Company Gas entered into a stock purchase agreement for the sale of Pivotal Home Solutions. In contemplation of this transaction and based on the purchase price, a goodwill impairment charge of $42 million was recorded in the first quarter 2018. See Note 15 under "Southern Company Gas" for additional information.

(b) Gas distribution operations reflects goodwill allocated to Elizabethtown Gas, Elkton Gas, and Florida City Gas, which were sold during the third quarter 2018. Gas marketing services reflects goodwill associated with Pivotal Home Solutions, which was sold on June 4, 2018. See Note 15 under "Southern Company Gas" for additional information.

(c) Total does not add due to rounding.

At December 31, 2018 and 2017, other intangible assets were as follows:

	At December 31, 2018			At December 31, 2017		
	Gross Carrying Amount	Accumulated Amortization	Other Intangible Assets, Net	Gross Carrying Amount	Accumulated Amortization	Other Intangible Assets, Net
		(in millions)			*(in millions)*	
Southern Company						
Other intangible assets subject to amortization:						
Customer relationships[a]	$ 223	$ (94)	$ 129	$ 288	$ (83)	$ 205
Trade names[a]	70	(21)	49	159	(17)	142
Storage and transportation contracts	64	(54)	10	64	(34)	30
PPA fair value adjustments[b]	405	(61)	344	456	(47)	409
Other	11	(5)	6	17	(5)	12
Total other intangible assets subject to amortization	$ 773	$ (235)	$ 538	$ 984	$ (186)	$ 798
Other intangible assets not subject to amortization:						
Federal Communications Commission licenses	75	—	75	75	—	75
Total other intangible assets	$ 848	$ (235)	$ 613	$ 1,059	$ (186)	$ 873
Southern Power						
Other intangible assets subject to amortization:						
PPA fair value adjustments[b]	$ 405	$ (61)	$ 344	$ 456	$ (47)	$ 409
Southern Company Gas						
Other intangible assets subject to amortization:						
Gas marketing services[a]						
Customer relationships	$ 156	$ (84)	$ 72	$ 221	$ (77)	$ 144
Trade names	26	(7)	19	115	(9)	106
Wholesale gas services						
Storage and transportation contracts	64	(54)	10	64	(34)	30
Total other intangible assets subject to amortization	$ 246	$ (145)	$ 101	$ 400	$ (120)	$ 280

(a) Balances as of December 31, 2018 reflect the sale of Pivotal Home Solutions. See Note 15 under "Southern Company Gas – Sale of Pivotal Home Solutions" for additional information.

(b) Balances as of December 31, 2018 exclude Plant Mankato-related intangible assets that were reclassified as assets held for sale. See Note 15 under "Southern Power – Sales of Natural Gas Plants" for additional information.

Amortization associated with other intangible assets in 2018, 2017, and 2016 was as follows:

	2018	2017	2016
		(in millions)	
Southern Company	$ 89	$ 124	$ 50
Southern Power	$ 25	$ 25	$ 10

	Successor			Predecessor
	Year Ended December 31, 2018	Year Ended December 31, 2017	July 1, 2016 through December 31, 2016	January 1, 2016 through June 30, 2016
		(in millions)		*(in millions)*
Southern Company Gas:				
Wholesale gas services[a]	$ 20	$ 32	$ 2	$ —
Gas marketing services[b]	32	54	32	8

(a) Recorded as a reduction to operating revenues.

(b) Included in depreciation and amortization.

At December 31, 2018, the estimated amortization associated with other intangible assets for the next five years is as follows:

	2019	**2020**	**2021**	**2022**	**2023**
			(in millions)		
Southern Company[*]	$ 61	$ 50	$ 43	$ 39	$ 38
Southern Power[*]	20	20	20	20	20
Southern Company Gas	29	19	13	10	9

(*) Excludes amounts related to held for sale assets. See Note 15 under "Southern Power – Sales of Natural Gas Plants" for additional information.

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, 2018, the accumulated amortization of these intangible liabilities was $74 million. In 2019, the remaining $17 million of amortization associated with the intangible liabilities will be recorded in natural gas revenues.

Acquisition Accounting

At the time of an acquisition, management will assess whether acquired assets and activities meet the definition of a business. For acquisitions that meet the definition of a business, operating results from the date of acquisition are included in the acquiring entity's 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 management 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 for potential or successful acquisitions are expensed as incurred.

Historically, contingent consideration primarily relates to fixed amounts due to the seller once an acquired construction project is placed in service. For contingent consideration with variable payments, management fair values the arrangement with any changes recorded in the statements of income. See Note 13 for additional fair value information.

Development Costs

For Southern Power, development costs are capitalized 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. Southern Power's capitalized development costs are included in CWIP on the balance sheets. All of Southern Power's 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 statements of income. If it is determined that a project is no longer probable of completion, any of Southern Power's capitalized development costs are expensed and included in other operations and maintenance expense in the statements of income.

Long-Term Service Agreements

The traditional electric operating companies and Southern Power have entered into LTSAs for the purpose of securing maintenance support for certain of their 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 for the performance of any planned inspections or unplanned capital maintenance are recorded in the statements of cash flows as investing activities. Receipts of major parts into materials and supplies inventory prior to planned inspections are treated as noncash transactions in the statements of cash flows. Any payments made prior to the work being performed are recorded as prepayments in other current assets and noncurrent assets on the balance sheets. At the time work is performed, an appropriate amount is accrued for future payments or transferred from the prepayment and recorded as property, plant, and equipment or expensed.

Transmission Receivables/Prepayments

As a result of Southern Power's acquisition and construction of generating facilities, Southern Power has transmission receivables and/or prepayments representing the portion of interconnection network and transmission upgrades that will be reimbursed to Southern Power. 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.

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.

Restricted Cash

The registrants adopted ASU 2016-18 as of January 1, 2018. See "Recently Adopted Accounting Standards – Other" herein for additional information.

At December 31, 2018, Georgia Power had restricted cash related to the redemption of pollution control revenue bonds, which were redeemed subsequent to December 31, 2018. See Note 8 under "Long-term Debt – Pollution Control Revenue Bonds" for additional information. At December 31, 2017, Southern Power had restricted cash primarily related to certain acquisitions and construction projects. At December 31, 2018 and 2017, Southern Company Gas had restricted cash held as collateral for worker's compensation, life insurance, and long-term disability insurance.

The following tables provide a reconciliation of cash, cash equivalents, and restricted cash reported within the balance sheets that total to the amounts shown in the statements of cash flows for the registrants that had restricted cash at December 31, 2018 and/or 2017:

	Southern Company	Georgia Power	Southern Company Gas
		(in millions)	
At December 31, 2018			
Cash and cash equivalents	$ 1,396	$ 4	$ 64
Cash and cash equivalents classified as assets held for sale	9	—	—
Restricted cash:			
Restricted cash	—	108	—
Other accounts and notes receivable	114	—	6
Total cash, cash equivalents, and restricted cash	$ 1,519	$ 112	$ 70

	Southern Company	Southern Power	Southern Company Gas
		(in millions)	
At December 31, 2017			
Cash and cash equivalents	$ 2,130	$ 129	$ 73
Restricted cash:			
Other accounts and notes receivable	5	—	5
Deferred charges and other assets	12	11	—
Total cash, cash equivalents, and restricted cash	$ 2,147	$ 140	$ 78

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, for Mississippi Power, 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 the following amounts related to storm damage reserves in 2018, 2017, and 2016:

	Southern Company(*)	Alabama Power	Georgia Power	Mississippi Power
		(in millions)		
2018	$ 74	$ 16	$ 30	$ 1
2017	41	4	30	3
2016	40	3	30	4

(*) Includes accruals at Gulf Power of $26.9 million in 2018 and $3.5 million in each of 2017 and 2016. See Note 15 under "Southern Company's Sale of Gulf Power" for information regarding the sale of Gulf Power.

Alabama Power and Mississippi Power also have authority based on orders from their state PSCs to accrue certain additional amounts as circumstances warrant. There were no such additional accruals for Alabama Power and Mississippi Power in any year presented.

See Note 2 under "Alabama Power – Rate NDR," "Georgia Power – Storm Damage Recovery," and "Mississippi Power – System Restoration Rider" for additional information regarding each company's storm damage reserve.

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 2017, the financial and operational performance of one of the lessees and the associated generation assets 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. As a result of operational improvements in 2018, the 2018 lease payments were paid in full. However, operational issues and the resulting cash liquidity challenges persist and significant concerns continue regarding the lessee's ability to make the remaining semi-annual lease payments. These operational challenges may also impact the expected residual value of the assets at the end of the lease term in 2047. If 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 could 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 would result in a reduction in net income of approximately $86 million after tax based on the lease receivable balance at December 31, 2018. 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 at December 31, 2018. 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. 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:

	2018	2017
	(in millions)	
Net rentals receivable	**$ 1,563**	$ 1,498
Unearned income	**(765)**	(723)
Investment in leveraged leases	**798**	775
Deferred taxes from leveraged leases	**(255)**	(252)
Net investment in leveraged leases	**$ 543**	$ 523

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

	2018	2017	2016
		(in millions)	
Pretax leveraged lease income	**$ 25**	$ 25	$ 25
Net impact of Tax Reform Legislation	**—**	48	—
Income tax expense	**(6)**	(9)	(9)
Net leveraged lease income	**$ 19**	$ 64	$ 16

Materials and Supplies

Materials and supplies for the traditional electric operating companies generally includes the average cost of transmission, distribution, and generating plant materials. Materials and supplies for Southern Company Gas generally includes propane gas inventory, fleet fuel, and other materials and supplies. Materials and supplies for Southern Power generally includes the average cost of generating plant materials.

Materials are recorded to 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 for the traditional electric operating companies includes the average cost of coal, natural gas, oil, transportation, and emissions allowances. Fuel inventory for Southern Power, which is included in other current assets, includes the average cost of oil, natural gas, biomass, and emissions allowances. Fuel is recorded to inventory when purchased and then expensed, at weighted average cost, as used. Emissions allowances granted by the EPA are included in inventory at zero cost. The traditional electric operating companies recover fuel expense through fuel cost recovery rates approved by each state PSC or, for wholesale rates, the FERC.

Natural Gas for Sale

With the exception of Nicor Gas, the natural gas distribution utilities record natural gas inventories on a WACOG basis. In Georgia's deregulated, competitive environment, Marketers sell natural gas to firm end-use customers at market-based prices. 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' 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 or Southern Company Gas' net income. At December 31, 2018, the Nicor Gas LIFO inventory balance was $165 million. Based on the average cost of gas purchased in December 2018, the estimated replacement cost of Nicor Gas' inventory at December 31, 2018 was $409 million. During 2018, Nicor Gas did not liquidate any LIFO-based inventory.

Southern Company Gas' gas marketing services, wholesale gas services, and all other segments record inventory at LOCOM, with cost determined on a WACOG basis. For these segments, Southern Company Gas 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, Southern Company Gas recorded LOCOM adjustments to cost of natural gas to reduce the value of its natural gas inventories to market value. LOCOM adjustments were $10 million during 2018 for wholesale gas services and immaterial for all other periods presented.

Energy Marketing Receivables and Payables

Southern Company Gas' 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. Southern Company Gas' wholesale gas services also nets across product lines and against cash collateral, provided the 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.

Southern Company Gas' 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 Southern Company Gas' credit ratings are downgraded to non-investment grade status. Under such circumstances, Southern Company Gas' wholesale gas services would need to post collateral to continue transacting business with some of its counterparties. As of December 31, 2018 and 2017, the required collateral in the event of a credit rating downgrade was $30 million and $8 million, respectively.

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 Southern Company Gas' 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 Southern Company Gas' credit risk. Southern Company Gas' wholesale gas services also uses other netting agreements with certain counterparties with whom it conducts significant transactions.

See "Concentration of Credit Risk" herein for additional information.

Provision for Uncollectible Accounts

The customers of the traditional electric operating companies and natural gas distribution utilities are billed monthly. 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 reasonably expected to be collected. 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. For all periods presented, uncollectible accounts averaged less than 1% of revenues for each registrant.

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.

Concentration of Credit Risk

Southern Company Gas' wholesale gas services business 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 a 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, 2018, the top 20 counterparties represented 48%, or $298 million, of the total counterparty exposure and had a weighted average S&P equivalent rating of A-.

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 (including SouthStar). 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.

Financial Instruments

The traditional electric operating companies and Southern Power 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. Southern Company Gas 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 (included in "Other" or shown separately as "Risk Management Activities") and are measured at fair value. See Note 13 for additional information regarding fair value. Substantially all of the traditional electric operating companies' and Southern Power'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 AOCI or regulatory assets and liabilities, respectively, until the hedged transactions occur. For 2017 and 2016, ineffectiveness arising from cash flow hedges was recognized in net income. Upon the adoption of ASU 2017-12 in 2018, ineffectiveness is no longer separately measured and recorded in earnings. See "Recently Adopted Accounting Standards" herein for additional information. 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 14 for additional information regarding derivatives.

The registrants offset fair value amounts recognized for multiple derivative instruments executed with the same counterparty under netting arrangements. The registrants had no outstanding collateral repayment obligations or rights to reclaim collateral arising from derivative instruments recognized at December 31, 2018.

The registrants are exposed to potential losses related to financial instruments in the event of counterparties' nonperformance. The registrants have established risk management policies and controls to determine and monitor the creditworthiness of counterparties in order to mitigate their exposure to counterparty credit risk.

Southern Company Gas

Southern Company Gas 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. Southern Company Gas 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.

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 attributable to the registrant, changes in the fair value of qualifying cash flow hedges, and reclassifications for amounts included in net income. Comprehensive income also consists of certain changes in pension and other postretirement benefit plans for Southern Company, Southern Power, and Southern Company Gas.

AOCI (loss) balances, net of tax effects, for Southern Company, Southern Power, and Southern Company Gas were as follows:

	Qualifying Hedges	Pension and Other Postretirement Benefit Plans	Accumulated Other Comprehensive Income (Loss)
		(in millions)	
Southern Company			
Balance at December 31, 2017	$ (119)	$ (70)	$ (189)
Adjustment to beginning balance(*)	(26)	(14)	(40)
Current period change	24	2	26
Balance at December 31, 2018	**$ (121)**	**$ (82)**	**$ (203)**
Southern Power			
Balance at December 31, 2017	$ 25	$ (27)	$ (2)
Adjustment to beginning balance(*)	4	—	4
Current period change	7	7	14
Balance at December 31, 2018	**$ 36**	**$ (20)**	**$ 16**
Southern Company Gas			
Balance at December 31, 2017	$ (6)	$ 26	$ 20
Adjustment to beginning balance(*)	(1)	5	4
Current period change	4	(2)	2
Balance at December 31, 2018	**$ (3)**	**$ 29**	**$ 26**

(*) Reflects the reclassification related to stranded tax effects resulting from the Tax Reform Legislation as allowed by ASU 2018-02. See "Recently Adopted Accounting Standards – Other" herein for additional information.

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. See Note 7 for additional information regarding VIEs.

Alabama Power has established a wholly-owned trust to issue preferred securities. See Note 8 under "Long-term Debt – Other Long-Term Debt – Alabama Power" for additional information. However, Alabama Power 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 Alabama Power's balance sheets.

2. REGULATORY MATTERS

Southern Company

Regulatory Assets and Liabilities

Regulatory assets and (liabilities) reflected in the consolidated balance sheets of Southern Company at December 31, 2018 and 2017 relate to:

	2018	2017	Note
	(in millions)		
Retiree benefit plans	**$ 3,658**	$ 3,931	(a,p)
Asset retirement obligations-asset	**2,933**	1,133	(b,p)
Deferred income tax charges	**799**	814	(b,o)
Property damage reserves-asset	**416**	333	(c)
Under recovered regulatory clause revenues	**407**	317	(d)
Environmental remediation-asset	**366**	511	(e,p)
Loss on reacquired debt	**346**	223	(f)
Remaining net book value of retired assets	**211**	306	(g)
Vacation pay	**182**	183	(h,p)
Long-term debt fair value adjustment	**121**	138	(i)
Deferred PPA charges	**—**	119	(j,p)
Other regulatory assets	**581**	625	(k)
Deferred income tax credits	**(6,455)**	(7,261)	(b,o)
Other cost of removal obligations	**(2,297)**	(2,684)	(b)
Customer refunds	**(293)**	(188)	(n)
Property damage reserves-liability	**(76)**	(135)	(l)
Over recovered regulatory clause revenues	**(47)**	(155)	(d)
Other regulatory liabilities	**(132)**	(104)	(m)
Total regulatory assets (liabilities), net	**$ 720**	$ (1,894)	

Note: Unless otherwise noted, the recovery and amortization periods for these regulatory assets and (liabilities) are approved by the respective PSC or regulatory agency and are as follows:

(a) Recovered and amortized over the average remaining service period which may range up to 15 years. See Note 11 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. Included in the deferred income tax assets is $28 million for the retiree Medicare drug subsidy, which is being recovered and amortized through 2027.

(c) Through 2019, Georgia Power is recovering approximately $30 million annually for storm damage, which is expected to be adjusted in the Georgia Power 2019 Base Rate Case. See "Georgia Power – Storm Damage Recovery" herein for additional information.

(d) Recorded and recovered or amortized over periods generally not exceeding 10 years.

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

(f) 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.

(g) Amortized over periods not exceeding eight years.

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

(i) Recovered over the remaining life of the original debt issuances, which range up to 20 years. For additional information see Note 15 under "Southern Company Merger with Southern Company Gas."

(j) Related to Gulf Power and reclassified as assets held for sale at December 31, 2018. See Note 15 under "Southern Company's Sale of Gulf Power" for information regarding the sale of Gulf Power.

(k) Comprised of numerous immaterial components including nuclear outage, fuel-hedging losses, cancelled construction projects, building and generating plant leases, property tax, and other miscellaneous assets. These costs are recorded and recovered or amortized over periods generally not exceeding 50 years.

(l) Amortized as storm restoration and potential reliability-related expenses are incurred.

(m) Comprised of numerous components including retiree benefit plans, fuel-hedging gains, AROs, and other liabilities that are recorded and recovered or amortized over periods not exceeding 20 years.

(n) At December 31, 2018, represents amounts accrued and outstanding for refund, including approximately $109 million as a result of Alabama Power's 2018 retail return exceeding the allowed range, approximately $55 million pursuant to the Georgia Power Tax Reform Settlement Agreement, and approximately $100 million, subject to review and approval by the Georgia PSC, as a result of Georgia Power's 2018 retail ROE exceeding the allowed retail ROE range. See "Alabama Power – Rate RSE" and "Georgia Power – Rate Plans" herein for additional information.

(o) 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 in future rate proceedings. See "Georgia Power," "Mississippi Power," and "Southern Company Gas" herein and Note 10 for additional information.

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

Gulf Power

On January 1, 2019, Southern Company completed its sale of Gulf Power to NextEra Energy. See Note 15 under "Southern Company's Sale of Gulf Power" for additional information.

In accordance with a Florida PSC-approved settlement agreement, Gulf Power's rates effective for the first billing cycle in July 2017 increased by approximately $54 million annually (2017 Gulf Power Rate Case Settlement), including a $62 million increase in base revenues, less an $8 million purchased power capacity cost recovery clause credit. 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, which was recorded in the first quarter 2017.

As a continuation of the 2017 Gulf Power Rate Case Settlement Agreement, on March 26, 2018, the Florida PSC approved a stipulation and settlement agreement addressing Gulf Power's retail revenue requirement effects of the Tax Reform Legislation (Gulf Power Tax Reform Settlement Agreement). Beginning in April 1, 2018, the Gulf Power Tax Reform Settlement Agreement resulted in annual reductions of approximately $18 million to Gulf Power's base rates and approximately $16 million to Gulf Power's environmental cost recovery rates and a one-time refund of approximately $69 million for the retail portion of unprotected (not subject to normalization) deferred tax liabilities, which was credited to customers through Gulf Power's fuel cost recovery rates over the remainder of 2018.

Alabama Power

Regulatory Assets and Liabilities

Regulatory assets and (liabilities) reflected in the balance sheets of Alabama Power at December 31, 2018 and 2017 relate to:

	2018	2017	Note
	(in millions)		
Retiree benefit plans	**$ 947**	$ 946	(a,p)
Deferred income tax charges	**241**	240	(b,c,d,)
Under recovered regulatory clause revenues	**176**	53	(e)
Asset retirement obligations	**147**	(33)	(b)
Regulatory clauses	**142**	142	(f)
Vacation pay	**71**	70	(g,p)
Loss on reacquired debt	**56**	62	(h)
Nuclear outage	**49**	56	(i)
Remaining net book value of retired assets	**43**	54	(j)
Other regulatory assets	**57**	58	(k,l)
Deferred income tax credits	**(2,027)**	(2,082)	(b,d)
Other cost of removal obligations	**(497)**	(609)	(b)
Rate RSE refund	**(109)**	—	(m)
Natural disaster reserve	**(20)**	(38)	(n)
Other regulatory liabilities	**(45)**	(7)	(l,o)
Total regulatory assets (liabilities), net	**$ (769)**	$ (1,088)	

Note: Unless otherwise noted, the recovery and amortization periods for these regulatory assets and (liabilities) have been accepted or approved by the Alabama PSC and are as follows:

(a) Recovered and amortized over the average remaining service period which may range up to 15 years. See Note 11 for additional information.

(b) 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.

(c) Included in the deferred income tax charges are $10 million for 2018 and $13 million for 2017 for the retiree Medicare drug subsidy, which is being recovered and amortized through 2027.

(d) 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 occur ratably over the related property lives, which may range up to 50 years. See Note 10 for additional information.

(e) Recorded and recovered or amortized over periods not exceeding 10 years. See "Rate CNP PPA," "Rate CNP Compliance," and" Rate ECR" herein for additional information.

(f) Will be amortized concurrently with the effective date of Alabama Power's next depreciation study. See "Rate RSE" herein for additional information.

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

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

(i) Nuclear outage costs are deferred to a regulatory asset when incurred and amortized over a subsequent 18-month period.

(j) Recorded and amortized over remaining periods up to 8 years.

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

(l) 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.

(m) Refund accrued as a result of the 2018 retail return exceeding the allowed range. See "Rate RSE" herein for additional information.

(n) Amortized as storm restoration and potential reliability-related expenses are incurred.

(o) Comprised of several components, primarily $33 million deferred as a result of the Alabama PSC accounting order regarding the Tax Reform Legislation. See "Tax Reform Accounting Order" herein for additional information.

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

Rate RSE

The Alabama PSC has adopted Rate RSE that provides for periodic annual adjustments based upon Alabama Power's projected weighted common equity return (WCER) 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%. When the projected WCER is under the allowed range, there is an adjusting point of 5.98% and eligibility for a performance-based adder of seven basis points, or 0.07%, to the WCER 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. If Alabama Power's actual retail return is above the allowed WCER 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 WCER range. Prior to January 2019, retail rates remained unchanged when the WCER range was between 5.75% and 6.21%.

At December 31, 2016, Alabama Power's retail return exceeded the allowed WCER range which resulted in Alabama Power establishing a $73 million Rate RSE refund liability. In accordance with an Alabama PSC order issued in February 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 WCER range. Retail rates under Rate RSE were 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. In accordance with this tariff, Alabama Power returned $267 million to retail customers through bill credits during 2018 as a result of the change in the federal income tax rate under the Tax Reform Legislation.

On May 1, 2018, the Alabama PSC approved modifications to Rate RSE and other commitments designed to position Alabama Power to address the growing pressure on its credit quality resulting from the Tax Reform Legislation, without increasing retail rates under Rate RSE in the near term. Alabama Power plans to reduce growth in total debt by increasing equity, with corresponding reductions in debt issuances, thereby de-leveraging its capital structure. Alabama Power's goal is to achieve an equity ratio of approximately 55% by the end of 2025. At December 31, 2018, Alabama Power's equity ratio was approximately 47%.

The approved modifications to Rate RSE began for billings in January 2019. The modifications include reducing the top of the allowed WCER range from 6.21% to 6.15% and modifications to the refund mechanism applicable to prior year actual results. The modifications to the refund mechanism allow Alabama Power to retain a portion of the revenue that causes the actual WCER for a given year to exceed the allowed range.

Generally, if Alabama Power's actual WCER is between 6.15% and 7.65%, customers will receive 25% of the amount between 6.15% and 6.65%, 40% of the amount between 6.65% and 7.15%, and 75% of the amount between 7.15% and 7.65%. Customers will receive all amounts in excess of an actual WCER of 7.65%.

In conjunction with these modifications to Rate RSE, on May 8, 2018, Alabama Power consented to a moratorium on any upward adjustments under Rate RSE for 2019 and 2020 and will also return $50 million to customers through bill credits in 2019.

On November 30, 2018, Alabama Power made its required annual Rate RSE submission to the Alabama PSC of projected data for calendar year 2019. Projected earnings were within the specified range; therefore, retail rates under Rate RSE remain unchanged for 2019.

At December 31, 2018, Alabama Power's retail return exceeded the allowed WCER range, which resulted in Alabama Power establishing a regulatory liability of $109 million for Rate RSE refunds. In accordance with an Alabama PSC order issued on February 5, 2019, Alabama Power will apply $75 million to reduce the Rate ECR under recovered balance and the remaining $34 million will be refunded to customers through bill credits in July through September 2019.

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. No adjustments to Rate CNP PPA occurred during the period 2016 through 2018 and no adjustment is expected in 2019. At December 31, 2018 and 2017, Alabama Power had an under recovered Rate CNP PPA balance of $25 million and $12 million, respectively, which is included in deferred under recovered regulatory clause revenues in the balance sheet.

In accordance with an accounting order issued in February 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 no later than 2022. 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 Southern Company's or Alabama Power'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 Southern Company's or Alabama Power's net income.

In accordance with an accounting order issued in February 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 no later than 2022. Alabama Power's current depreciation study became effective January 1, 2017.

In December 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.

On November 30, 2018, Alabama Power submitted calculations associated with its cost of complying with environmental mandates, as provided under Rate CNP Compliance. The filing reflected a projected unrecovered retail revenue requirement for environmental compliance of approximately $205 million, which is being recovered in the billing months of January 2019 through December 2019.

At December 31, 2018, Alabama Power had an under recovered Rate CNP Compliance balance of $42 million, which is included in customer accounts receivable, and $17 million at December 31, 2017 included in deferred under recovered regulatory clause revenues in the balance sheet.

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 or Alabama Power's net income, but will impact operating cash flows.

In accordance with an accounting order issued in February 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 no later than 2022. Alabama Power's current depreciation study became effective January 1, 2017.

In December 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.

On May 1, 2018, the Alabama PSC approved an increase to Rate ECR from 2.015 cents per KWH to 2.353 cents per KWH effective July 2018 through December 2018. On December 4, 2018, the Alabama PSC issued a consent order to leave this rate in effect through December 31, 2019. This change is expected to increase collections by approximately $183 million in 2019. Absent any further order from the Alabama PSC, in January 2020, the rates will return to the originally authorized 5.910 cents per KWH.

As discussed herein under "Rate RSE," in accordance with an Alabama PSC order issued on February 5, 2019, Alabama Power will utilize $75 million of the 2018 Rate RSE refund liability to reduce the Rate ECR under recovered balance.

At December 31, 2018, Alabama Power's under recovered fuel costs totaled $109 million, of which $18 million is included in customer accounts receivable and $91 million is included in deferred under recovered regulatory clause revenues on Southern Company's and Alabama Power's balance sheets. At December 31, 2017, Alabama Power had an under recovered fuel balance of $25 million, which was included in deferred under recovered regulatory clause revenues on Southern Company's and Alabama Power's balance sheets. 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.

Tax Reform Accounting Order

On May 1, 2018, the Alabama PSC approved an accounting order that authorized Alabama Power to defer the benefits of federal excess deferred income taxes associated with the Tax Reform Legislation for the year ended December 31, 2018 as a regulatory liability and to use up to $30 million of such deferrals to offset under recovered amounts under Rate ECR. The estimated deferrals for the year ended December 31, 2018 totaled approximately $63 million, subject to adjustment following the filing of the 2018 tax return, of which $30 million was used to offset the Rate ECR under recovered balance and $33 million is recorded in other regulatory liabilities, deferred on the balance sheet to be used for the benefit of customers as determined by the Alabama PSC at a future date. See Note 10 under "Current and Deferred Income Taxes" for additional information.

Software Accounting Order

On February 5, 2019, the Alabama PSC approved an accounting order that authorizes Alabama Power to establish a regulatory asset for operations and maintenance costs associated with software implementation projects. The regulatory asset will be amortized ratably over the life of the related software.

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. 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, 2018 was $20 million and is included in other regulatory liabilities, deferred on the balance sheet.

The second component of the Rate NDR charge is intended to allow recovery of any existing deferred storm-related operations and maintenance costs and any future reserve deficits over a 24-month period. The Alabama PSC order gives Alabama Power authority to record a deficit balance in the NDR when costs of storm damage exceed any established reserve balance. Absent further Alabama PSC approval, the maximum total Rate NDR charge consisting of both components is $10 per month per non-residential customer account and $5 per month per residential customer account. Alabama Power has the authority, based on an order from the Alabama PSC, to accrue certain additional amounts as circumstances warrant. The order allows for reliability-related expenditures to be charged against the additional accruals when the NDR balance exceeds $75 million. Alabama Power may designate a portion of the NDR to reliability-related expenditures as a part of an annual budget process for the following year or during the current year for identified unbudgeted reliability-related expenditures that are incurred. Accruals that have not been designated can be used to offset storm charges. Additional accruals to the NDR will enhance Alabama Power's ability to deal with the financial effects of future natural disasters, promote system reliability, and offset costs retail customers would otherwise bear. No such accruals were recorded or designated in any period presented.

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

Environmental Accounting Order

Based on an order from the Alabama PSC (Environmental Accounting Order), 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 is being amortized and recovered over the affected unit's remaining useful life, as established prior to the decision regarding early retirement through Rate CNP Compliance. At December 31, 2018, this regulatory asset had a balance of $42

million, of which $10 million is included in other regulatory assets, current and $32 million is included in other regulatory assets, deferred on the balance sheet.

Subsequent to December 31, 2018, Alabama Power determined that Plant Gorgas Units 8, 9, and 10 (approximately 1,000 MWs) will be retired by April 15, 2019 due to the expected costs of compliance with federal and state environmental regulations. In accordance with the Environmental Accounting Order, approximately $740 million of net investment costs will be transferred to a regulatory asset at the retirement date and recovered over the affected units' remaining useful lives, as established prior to the decision to retire.

Georgia Power

Regulatory Assets and Liabilities

Regulatory assets and (liabilities) reflected in the balance sheets of Georgia Power at December 31, 2018 and 2017 relate to:

	2018	2017	Note
	(in millions)		
Retiree benefit plans	**$ 1,295**	$ 1,313	(a, l)
Asset retirement obligations	**2,644**	945	(b, l)
Deferred income tax charges	**522**	521	(b, c, l)
Storm damage reserves	**416**	333	(d)
Remaining net book value of retired assets	**127**	146	(e)
Loss on reacquired debt	**277**	127	(f, l)
Vacation pay	**91**	91	(g, l)
Other cost of removal obligations	**68**	40	(b)
Environmental remediation	**55**	49	(h)
Other regulatory assets	**135**	106	(i)
Deferred income tax credits	**(3,080)**	(3,248)	(b, c)
Customer refunds	**(165)**	(188)	(j)
Other regulatory liabilities	**(7)**	(3)	(k, l)
Total regulatory assets (liabilities), net	**$ 2,378**	$ 232	

Note: Unless otherwise noted, the recovery and amortization periods for these regulatory assets and (liabilities) are approved by the Georgia PSC and are as follows:

(a) Recovered and amortized over the average remaining service period which may range up to 14 years. See Note 11 for additional information.

(b) Through 2019, Georgia Power is recovering approximately $60 million annually for AROs, which is expected to be adjusted in the Georgia Power 2019 Base Rate Case. Asset retirement and removal liabilities will be settled and trued up following completion of the related activities. See Note 6 for additional information on AROs. 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. Included in the deferred income tax assets is $17 million for the retiree Medicare drug subsidy, which is being recovered and amortized through 2022.

(c) As a result of the Tax Reform Legislation, these balances include $145 million of deferred income tax assets related to CWIP for Plant Vogtle Units 3 and 4 and approximately $610 million of deferred income tax liabilities, neither of which are subject to normalization. The recovery and amortization of these amounts is expected to be determined in the Georgia Power 2019 Base Rate Case. See "Rate Plans" herein and Note 10 for additional information.

(d) Through 2019, Georgia Power is recovering approximately $30 million annually for storm damage, which is expected to be adjusted in the Georgia Power 2019 Base Rate Case. See "Storm Damage Recovery" herein and Note 1 under "Storm Damage Reserves" for additional information.

(e) The net book value of Plant Branch Units 1 through 4 at December 31, 2018 was $87 million, which is being amortized over the units' remaining useful lives through 2024. The net book value of Plant Mitchell Unit 3 at December 31, 2018 was $9 million, which will continue to be amortized through December 31, 2019 as provided in the 2013 ARP. Amortization of the remaining approximately $4 million net book value of Plant Mitchell Unit 3 at December 31, 2019 and a total of approximately $31 million related to obsolete inventories of certain retired units is expected to be determined in the Georgia Power 2019 Base Rate Case. See "Integrated Resource Plan" herein 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 34 years.

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

(h) Through 2019, Georgia Power is recovering approximately $2 million annually for environmental remediation, which is expected to be adjusted in the Georgia Power 2019 Base Rate Case. See Note 3 under Environmental Remediation for additional information.

(i) Comprised of several components including future generation costs, deferred nuclear outage costs, cancelled construction projects, building lease, and fuel-hedging losses. The timing of recovery of approximately $50 million for a future generation site is expected to be determined in the Georgia Power 2019 Base Rate Case. Nuclear outage costs are recorded and recovered or amortized over the outage cycles of each nuclear unit, which do not exceed 24 months. Approximately $30 million of costs associated with construction of environmental controls that will not be completed as a result of unit retirements are being amortized through 2022. The building lease is recorded and recovered or amortized through 2020. Fuel-hedging losses are recovered through Georgia Power's fuel cost recovery mechanism upon final settlement. See "Integrated Resource Plan" herein for additional information on future generation costs.

(j) At December 31, 2018, approximately $55 million was accrued and outstanding for refund pursuant to the Georgia Power Tax Reform Settlement Agreement and approximately $100 million was accrued for refund, subject to review and approval by the Georgia PSC, as a result of the 2018 retail ROE exceeding the allowed retail ROE range. See "Rate Plans" herein for additional information.

(k) Comprised of Demand-Side Management (DSM) tariff over recovery and fuel-hedging gains. The amortization of DSM tariff over recovery of $3 million at December 31, 2018 is expected to be determined in the Georgia Power 2019 Base Rate Case. Fuel-hedging gains are refunded through Georgia Power's fuel cost recovery mechanism upon final settlement. See "Rate Plans" herein for additional information on customer refunds and DSM tariffs.

(l) Generally not earning a return as they are excluded from rate base or are offset in rate base by a corresponding asset or liability.

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 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 will retain its merger savings, net of transition costs, as defined in the settlement agreement; through December 31, 2022, such net merger savings will be shared on a 60/40 basis with customers; thereafter, all merger savings will be retained by customers.

There were no changes to Georgia Power's traditional base tariff rates, Environmental Compliance Cost Recovery (ECCR) tariff, DSM tariffs, or Municipal Franchise Fee tariff in 2017 or 2018.

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 2016, Georgia Power's retail ROE exceeded 12.00%, and Georgia Power refunded to retail customers in 2018 approximately $40 million as approved by the Georgia PSC. On February 5, 2019, the Georgia PSC approved a settlement between Georgia Power and the staff of the Georgia PSC under which Georgia Power's retail ROE for 2017 was stipulated to exceed 12.00% and Georgia Power will reduce certain regulatory assets by approximately $4 million in lieu of providing refunds to retail customers. In 2018, Georgia Power's retail ROE exceeded 12.00%, and Georgia Power accrued approximately $100 million to refund to retail customers, subject to review and approval by the Georgia PSC.

On April 3, 2018, the Georgia PSC approved the Georgia Power Tax Reform Settlement Agreement. Pursuant to the Georgia Power Tax Reform Settlement Agreement, to reflect the federal income tax rate reduction impact of the Tax Reform Legislation, Georgia Power will refund to customers a total of $330 million through bill credits. Georgia Power issued bill credits of approximately $130 million in 2018 and will issue bill credits of approximately $95 million in June 2019 and $105 million in February 2020. In addition, Georgia Power is deferring as a regulatory liability (i) the revenue equivalent of the tax expense reduction resulting from legislation lowering the Georgia state income tax rate from 6.00% to 5.75% in 2019 and (ii) the entire benefit of federal and state excess accumulated deferred income taxes, which is expected to total approximately $700 million at December 31, 2019. At December 31, 2018, the related regulatory liability balance totaled $610 million. The amortization of these regulatory liabilities is expected to be addressed in the Georgia Power 2019 Base Rate Case. If there is not a base rate case in 2019, customers will receive $185 million in annual bill credits beginning in 2020, with any additional federal and state income tax savings deferred as a regulatory liability, until Georgia Power's next base rate case.

To address some of the negative cash flow and credit quality impacts of the Tax Reform Legislation, the Georgia PSC also approved an increase in Georgia Power's retail equity ratio to the lower of (i) Georgia Power's actual common equity weight in its capital structure or (ii) 55%, until the Georgia Power 2019 Base Rate Case. At December 31, 2018, Georgia Power's actual retail common equity ratio (on a 13-month average basis) was approximately 55%. Benefits from reduced federal income tax rates in excess of the amounts refunded to customers will be retained by Georgia Power to cover the carrying costs of the incremental equity in 2018 and 2019.

Integrated Resource Plan

In 2016, the Georgia PSC approved Georgia Power's triennial Integrated Resource Plan (2016 IRP) including 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 Georgia Power 2019 Base Rate Case.

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. In March 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 the Georgia Power 2019 Base Rate Case.

On January 31, 2019, Georgia Power filed its triennial IRP (2019 IRP). The filing includes a request to decertify and retire Plant Hammond Units 1 through 4 (840 MWs) and Plant McIntosh Unit 1 (142.5 MWs) upon approval of the 2019 IRP.

In the 2019 IRP, Georgia Power requested approval to reclassify the remaining net book value of Plant Hammond Units 1 through 4 (approximately $520 million at December 31, 2018) upon retirement to a regulatory asset to be amortized ratably over a period equal to the applicable unit's remaining useful life through 2035. For Plant McIntosh Unit 1, Georgia Power requested approval to

reclassify the remaining net book value (approximately $40 million at December 31, 2018) upon retirement to a regulatory asset to be amortized over a three-year period to be determined in the Georgia Power 2019 Base Rate Case. Georgia Power also requested approval to reclassify any unusable material and supplies inventory balances remaining at the applicable unit's retirement date to a regulatory asset for recovery over a period to be determined in the Georgia Power 2019 Base Rate Case.

The 2019 IRP also includes a request to certify approximately 25 MWs of capacity at Plant Scherer Unit 3 for the retail jurisdiction beginning January 1, 2020, following the expiration of a wholesale PPA.

The 2019 IRP also includes details regarding ARO costs associated with ash pond and landfill closures and post-closure care. Georgia Power requested the timing and rate of recovery of these costs be determined by the Georgia PSC in the Georgia Power 2019 Base Rate Case. See Note 6 for additional information regarding Georgia Power's AROs.

Georgia Power also requested approval to issue two capacity-based requests for proposals (RFP). If approved, the first capacity-based RFP will seek resources that can provide capacity beginning in 2022 or 2023 and the second capacity-based RFP will seek resources that can provide capacity beginning in 2026, 2027, or 2028. Additionally, the 2019 IRP includes a request to procure an additional 1,000 MWs of renewable resources through a competitive bidding process. Georgia Power also proposed to invest in a portfolio of up to 50 MWs of battery energy storage technologies.

A decision from the Georgia PSC on the 2019 IRP is expected in mid-2019.

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

Fuel Cost Recovery

Georgia Power has established fuel cost recovery rates approved by the Georgia PSC. In 2016, the Georgia PSC approved Georgia Power's request to lower annual billings under an interim fuel rider by approximately $313 million effective June 1, 2016, which expired on December 31, 2017. On August 16, 2018, the Georgia PSC approved the deferral of Georgia Power's next fuel case to no later than March 16, 2020, with new rates, if any, to be effective June 1, 2020. 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 or over recovered fuel balance exceeds $200 million. Georgia Power's under recovered fuel balance totaled $115 million and $165 million at December 31, 2018 and 2017, respectively, and is included in under recovered fuel clause revenues on Southern Company's and Georgia Power's balance sheets.

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.

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 or Georgia Power's revenues or net income, but will affect operating cash flows.

Storm Damage Recovery

Georgia Power defers and recovers certain costs related to damages from major storms as mandated by the Georgia PSC. Beginning January 1, 2014, Georgia Power is accruing $30 million annually under the 2013 ARP that is recoverable through base rates. At December 31, 2018 and 2017, the balance in the regulatory asset related to storm damage was $416 million and $333 million, respectively, with $30 million included in other regulatory assets, current for each year and $386 million and $303 million included in other regulatory assets, deferred, respectively. During October 2018, Hurricane Michael caused significant damage to Georgia Power's transmission and distribution facilities. The incremental restoration costs related to this hurricane deferred in the regulatory asset for storm damage totaled approximately $115 million. Hurricanes Irma and Matthew also caused significant damage to Georgia Power's transmission and distribution facilities during September 2017 and October 2016, respectively. The incremental restoration costs related to Hurricanes Irma and Matthew deferred in the regulatory asset for storm damage totaled approximately $250 million. The rate of storm damage cost recovery is expected to be adjusted as part of the Georgia Power 2019 Base Rate Case and further adjusted in future regulatory proceedings as necessary. The ultimate outcome of this matter cannot be determined at this time.

Nuclear Construction

In 2009, the Georgia PSC certified construction of Plant Vogtle Units 3 and 4. Georgia Power holds a 45.7% ownership interest in 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. In March 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 in July 2017 when Georgia Power, acting for itself and as agent for the other Vogtle Owners, and the EPC Contractor entered into the Vogtle Services Agreement. Under the Vogtle Services Agreement, Westinghouse provides facility design and engineering services, procurement and technical support, and staff augmentation on a time and materials cost basis. The Vogtle Services Agreement provides that it 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.

In October 2017, Georgia Power, acting for itself and as agent for the other Vogtle Owners, executed the Bechtel Agreement, a cost reimbursable plus fee arrangement, whereby Bechtel is 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.

Cost and Schedule

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

		(in billions)
Base project capital cost forecast[(a)(b)]	$	8.0
Construction contingency estimate		0.4
Total project capital cost forecast[(a)(b)]		8.4
Net investment as of December 31, 2018[(b)]		(4.6)
Remaining estimate to complete[(a)]	**$**	**3.8**

(a) Excludes financing costs expected to be capitalized through AFUDC of approximately $315 million.

(b) Net of $1.7 billion received from Toshiba under the Guarantee Settlement Agreement and approximately $188 million in related 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 $1.9 billion had been incurred through December 31, 2018.

As construction continues, challenges with management of contractors, subcontractors, and vendors; labor productivity, availability, and/or cost escalation; procurement, fabrication, delivery, assembly, and/or installation and testing, including any required engineering changes, of plant systems, structures, and components (some of which are based on new technology that only recently began initial operation in the global nuclear industry at this scale); or other issues could arise and change the projected schedule and estimated cost. Monthly construction production targets required to maintain the current project schedule will continue to increase significantly throughout 2019. To meet these increasing monthly targets, existing craft construction productivity must improve and additional craft laborers must be retained and deployed.

Georgia Power and Southern Nuclear believe it is a leading practice in connection with a construction project of this size and complexity to periodically validate recent construction progress in comparison to the projected schedule and to verify and update quantities of commodities remaining to install, labor productivity, and forecasted staffing needs. This verification process, led by Southern Nuclear, was underway as of December 31, 2018 and is expected to be completed during the second quarter 2019. Georgia Power currently does not anticipate any material changes to the total estimated project capital cost forecast for Plant Vogtle Units 3 and 4 or the expected in-service dates of November 2021 and November 2022, respectively, resulting from this verification process. However, the ultimate impact on cost and schedule, if any, will not be known until the verification process is completed. Georgia Power is required to report the results and any project impacts to the Georgia PSC by May 15, 2019.

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 ITAAC 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. However, any extension of the project schedule is currently estimated to result in additional base capital costs of approximately $50 million per month, based on Georgia Power's ownership interests, and AFUDC of approximately $12 million per month. While Georgia Power is not precluded from seeking recovery of any future capital cost forecast increase, management will ultimately determine whether or not to seek recovery. Any further changes to the capital cost forecast that are not expected to be recoverable through regulated rates will be required to be charged to income and such charges could be material.

Joint Owner Contracts

In November 2017, the Vogtle Owners entered into an amendment to their joint ownership agreements for Plant Vogtle Units 3 and 4 to provide for, among other conditions, additional Vogtle Owner approval requirements. Effective August 31, 2018, the Vogtle Owners further amended the joint ownership agreements to clarify and provide procedures for certain provisions of the joint ownership agreements related to adverse events that require the vote of the holders of at least 90% of the ownership interests in Plant Vogtle Units 3 and 4 to continue construction (as amended, and together with the November 2017 amendment, the Vogtle Joint Ownership Agreements). 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.

As a result of the increase in the total project capital cost forecast and Georgia Power's decision not to seek rate recovery of the increase in the base capital costs as described below, the holders of at least 90% of the ownership interests in Plant Vogtle Units 3 and 4 were required to vote to continue construction. On September 26, 2018, the Vogtle Owners unanimously voted to continue construction of Plant Vogtle Units 3 and 4.

Amendments to the Vogtle Joint Ownership Agreements

In connection with the vote to continue construction, Georgia Power entered into (i) a binding term sheet (Vogtle Owner Term Sheet) with the other Vogtle Owners and MEAG's wholly-owned subsidiaries MEAG Power SPVJ, LLC (MEAG SPVJ), MEAG Power SPVM, LLC (MEAG SPVM), and MEAG Power SPVP, LLC (MEAG SPVP) to take certain actions which partially mitigate potential financial exposure for the other Vogtle Owners, including additional amendments to the Vogtle Joint Ownership Agreements and the purchase of PTCs from the other Vogtle Owners, and (ii) a term sheet (MEAG Term Sheet) with MEAG and MEAG SPVJ to provide funding with respect to MEAG SPVJ's ownership interest in Plant Vogtle Units 3 and 4 (Project J) under certain circumstances. On January 14, 2019, Georgia Power, MEAG, and MEAG SPVJ entered into an agreement to implement the provisions of the MEAG Term Sheet (MEAG Funding Agreement). On February 18, 2019, Georgia Power, the other Vogtle Owners, and MEAG's wholly-owned subsidiaries MEAG SPVJ, MEAG SPVM, and MEAG SPVP entered into certain amendments to the Vogtle Joint Ownership Agreements to implement the provisions of the Vogtle Owner Term Sheet (Global Amendments).

Pursuant to the Global Amendments, and consistent with the Vogtle Owner Term Sheet, the Vogtle Joint Ownership Agreements were modified as follows: (i) each Vogtle Owner must pay its proportionate share of qualifying construction costs for Plant Vogtle Units 3 and 4 based on its ownership percentage up to the estimated cost at completion (EAC) for Plant Vogtle Units 3 and 4 which formed the basis of Georgia Power's forecast of $8.4 billion in the nineteenth VCM plus $800 million; (ii) Georgia Power will be responsible for 55.7% of actual qualifying construction costs between $800 million and $1.6 billion over the EAC in the nineteenth VCM (resulting in $80 million of potential additional costs to Georgia Power), with the remaining Vogtle Owners responsible for 44.3% of such costs pro rata in accordance with their respective ownership interests; and (iii) Georgia Power will be responsible for 65.7% of qualifying construction costs between $1.6 billion and $2.1 billion over the EAC in the nineteenth VCM (resulting in a further $100 million of potential additional costs to Georgia Power), with the remaining Vogtle Owners responsible for 34.3% of such costs pro rata in accordance with their respective ownership interests.

If the EAC is revised and exceeds the EAC in the nineteenth VCM by more than $2.1 billion, each of the other Vogtle Owners will have a one-time option at the time the project budget forecast is so revised to tender a portion of its ownership interest to

Georgia Power in exchange for Georgia Power's agreement to pay 100% of such Vogtle Owner's remaining share of total construction costs in excess of the EAC in the nineteenth VCM plus $2.1 billion. In this event, Georgia Power will have the option of cancelling the project in lieu of purchasing a portion of the ownership interest of any other Vogtle Owner. If Georgia Power accepts the offer to purchase a portion of another Vogtle Owner's ownership interest in Plant Vogtle Units 3 and 4, the ownership interest(s) to be conveyed from the tendering Vogtle Owner(s) to Georgia Power will be calculated based on the proportion of the cumulative amount of construction costs paid by each such tendering Vogtle Owner(s) and by Georgia Power as of the COD of Plant Vogtle Unit 4. For purposes of this calculation, payments made by Georgia Power on behalf of another Vogtle Owner in accordance with the second and third items described in the paragraph above will be treated as payments made by the applicable Vogtle Owner.

In the event the actual costs of construction at completion of a Unit are less than the EAC reflected in the nineteenth VCM report and such Unit is placed in service in accordance with the schedule projected in the nineteenth VCM report (i.e., Plant Vogtle Unit 3 is placed in service by November 2021 or Plant Vogtle Unit 4 is placed in service by November 2022), Georgia Power will be entitled to 60.7% of the cost savings with respect to the relevant Unit and the remaining Vogtle Owners will be entitled to 39.3% of such savings on a pro rata basis in accordance with their respective ownership interests.

For purposes of the foregoing provisions, qualifying construction costs will not include costs (i) resulting from force majeure events, including governmental actions or inactions (or significant delays associated with issuance of such actions) that affect the licensing, completion, start-up, operations, or financing of Plant Vogtle Units 3 and 4, administrative proceedings or litigation regarding ITAAC or other regulatory challenges to commencement of operation of Plant Vogtle Units 3 and 4, and changes in laws or regulations governing Plant Vogtle Units 3 and 4, (ii) legal fees and legal expenses incurred due to litigation with contractors or subcontractors that are not subsidiaries or affiliates of Southern Company, and (iii) additional costs caused by requests from the Vogtle Owners other than Georgia Power, except for the exercise of a right to vote granted under the Vogtle Joint Ownership Agreements, that increase costs by $100,000 or more.

Pursuant to the Global Amendments, and consistent with the Vogtle Owner Term Sheet, the provisions of the Vogtle Joint Ownership Agreements requiring that Vogtle Owners holding 90% of the ownership interests in Plant Vogtle Units 3 and 4 vote to continue construction following certain adverse events (Project Adverse Events) were modified. Pursuant to the Global Amendments, the holders of at least 90% of the ownership interests in Plant Vogtle Units 3 and 4 must vote to continue construction if certain Project Adverse Events occur, including: (i) the bankruptcy of Toshiba; (ii) the termination or rejection in bankruptcy of certain agreements, including the Vogtle Services Agreement, the Bechtel Agreement, or the agency agreement with Southern Nuclear; (iii) Georgia Power publicly announces its intention not to submit for rate recovery any portion of its investment in Plant Vogtle Units 3 and 4 or the Georgia PSC 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, excluding any additional amounts paid by Georgia Power on behalf of the other Vogtle Owners pursuant to the Global Amendments described above and the first 6% of costs during any six-month VCM reporting period that are disallowed by the Georgia PSC for recovery, or for which Georgia Power elects not to seek cost recovery, through retail rates; and (iv) an incremental extension of one year or more over the most recently approved schedule. Under the Global Amendments, Georgia Power may cancel the project at any time in its sole discretion.

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 Global Amendments provide that if the holders of at least 90% of the ownership interests fail to vote in favor of continuing the project following any future Project Adverse Event, work on Plant Vogtle Units 3 and 4 will continue for a period of 30 days if the holders of more than 50% of the ownership interests vote in favor of continuing construction (Majority Voting Owners). In such a case, the Vogtle Owners (i) have agreed to negotiate in good faith towards the resumption of the project, (ii) if no agreement is reached during such 30-day period, the project will be cancelled, and (iii) in the event of such a cancellation, the Majority Voting Owners will be obligated to reimburse any other Vogtle Owner for the incremental costs it incurred during such 30-day negotiation period.

Purchase of PTCs During Commercial Operation

Pursuant to the Global Amendments, and consistent with the Vogtle Owner Term Sheet, Georgia Power has agreed to purchase additional PTCs from OPC, Dalton, MEAG SPVM, MEAG SPVP, and MEAG SPVJ (to the extent any MEAG SPVJ PTC rights remain after any purchases required under the MEAG Funding Agreement as described below) at varying purchase prices dependent upon the actual cost to complete construction of Plant Vogtle Units 3 and 4 as compared to the EAC reflected in the nineteenth VCM report. The purchases are at the option of the applicable Vogtle Owner.

Potential Funding to MEAG Project J

Pursuant to the MEAG Funding Agreement, and consistent with the MEAG Term Sheet, if MEAG SPVJ is unable to make its payments due under the Vogtle Joint Ownership Agreements solely as a result of the occurrence of one of the following situations that materially impedes access to capital markets for MEAG for Project J: (i) the conduct of JEA or the City of Jacksonville, such as JEA's legal challenges of its obligations under a PPA with MEAG (PPA-J), or (ii) PPA-J is declared void by a court of competent jurisdiction or rejected by JEA under the applicable provisions of the U.S. Bankruptcy Code (each of (i) and (ii), a JEA Default), at MEAG's request, Georgia Power will purchase from MEAG SPVJ the rights to PTCs attributable to MEAG SPVJ's share of Plant Vogtle Units 3 and 4 (approximately 206 MWs) within 30 days of such request at varying prices dependent upon the stage of construction of Plant Vogtle Units 3 and 4. The aggregate purchase price of the PTCs, together with any advances made as described in the next paragraph, shall not exceed $300 million.

At the option of MEAG, as an alternative or supplement to Georgia Power's purchase of PTCs as described above, Georgia Power has agreed to provide up to $250 million in funding to MEAG for Project J in the form of advances (either advances under the Vogtle Joint Ownership Agreements or the purchase of MEAG Project J bonds, at the discretion of Georgia Power), subject to any required approvals of the Georgia PSC and the DOE.

In the event MEAG SPVJ certifies to Georgia Power that it is unable to fund its obligations under the Vogtle Joint Ownership Agreements as a result of a JEA Default and Georgia Power becomes obligated to provide funding as described above, MEAG is required to (i) assign to Georgia Power its right to vote on any future Project Adverse Event and (ii) diligently pursue JEA for its breach of PPA-J. In addition, Georgia Power agreed that it will not sue MEAG for any amounts due from MEAG SPVJ under MEAG's guarantee of MEAG SPVJ's obligations so long as MEAG SPVJ complies with the terms of the MEAG Funding Agreement as to its payment obligations and the other non-payment provisions of the Vogtle Joint Ownership Agreements.

Under the terms of the MEAG Funding Agreement, Georgia Power may cancel the project in lieu of providing funding in the form of advances or PTC purchases.

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

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 Plant Vogtle Units 3 and 4. 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. At December 31, 2018, Georgia Power had recovered approximately $1.9 billion of financing costs. Financing costs related to capital costs above $4.418 billion will be recovered through AFUDC; however, Georgia Power will not record AFUDC related to any capital costs in excess of the total deemed reasonable by the Georgia PSC (currently $7.3 billion) and not requested for rate recovery. On December 18, 2018, the Georgia PSC approved Georgia Power's request to increase the NCCR tariff by $88 million annually, effective January 1, 2019.

Georgia Power is required to file semi-annual VCM reports with the Georgia PSC by February 28 and August 31 of each year. In 2013, in connection with the eighth VCM report, the Georgia PSC approved a 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.

In 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. In December 2017, the Georgia PSC voted to approve (and issued its related order on January 11, 2018) Georgia Power's seventeenth VCM report, which included a recommendation to continue construction with Southern Nuclear as project manager and Bechtel serving as the primary construction contractor, and modified 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 $5.68 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 $5.68 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 related Customer Refunds) was 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 $100 million, $25 million, and $20 million in 2018, 2017, and 2016, respectively, and are estimated to have negative earnings impacts of approximately $75 million in 2019 and an aggregate of approximately $615 million from 2020 to 2022.

In its January 11, 2018 order, the Georgia PSC also stated if other conditions change and assumptions upon which Georgia Power's seventeenth VCM report are based do not materialize, the Georgia PSC reserved the right to reconsider the decision to continue construction.

On February 12, 2018, Georgia Interfaith Power & Light, Inc. (GIPL) and Partnership for Southern Equity, Inc. (PSE) filed a petition appealing the Georgia PSC's January 11, 2018 order with the Fulton County Superior Court. On March 8, 2018, Georgia Watch filed a similar appeal to the Fulton County Superior Court for judicial review of the Georgia PSC's decision and denial of Georgia Watch's motion for reconsideration. On December 21, 2018, the Fulton County Superior Court granted Georgia Power's motion to dismiss the two appeals. On January 9, 2019, GIPL, PSE, and Georgia Watch filed an appeal of this decision with the Georgia Court of Appeals. Georgia Power believes the appeal has no merit; however, an adverse outcome in the appeal combined with subsequent adverse action by the Georgia PSC could have a material impact on Southern Company's and Georgia Power's results of operations, financial condition, and liquidity.

In preparation for its nineteenth VCM filing, Georgia Power requested Southern Nuclear to perform a full cost reforecast for the project. This reforecast, performed prior to the nineteenth VCM filing, resulted in a $0.7 billion increase to the base capital cost forecast reported in the second quarter 2018. This base cost increase primarily resulted from changed assumptions related to the finalization of contract scopes and management responsibilities for Bechtel and over 60 subcontractors, labor productivity rates, and craft labor incentives, as well as the related levels of project management, oversight, and support, including field supervision and engineering support.

Although Georgia Power believes these incremental costs are reasonable and necessary to complete the project and the Georgia PSC's order in the seventeenth VCM proceeding specifically states that the construction of Plant Vogtle Units 3 and 4 is not subject to a cost cap, Georgia Power did not seek rate recovery for these cost increases included in the current base capital cost forecast (or any related financing costs) in the nineteenth VCM report. In connection with future VCM filings, Georgia Power may request the Georgia PSC to evaluate costs currently included in the construction contingency estimate for rate recovery as and when they are appropriately included in the base capital cost forecast. After considering the significant level of uncertainty that exists regarding the future recoverability of costs included in the construction contingency estimate since the ultimate outcome of these matters is subject to the outcome of future assessments by management, as well as Georgia PSC decisions in these future regulatory proceedings, Georgia Power recorded a total pre-tax charge to income of $1.1 billion ($0.8 billion after tax) in the second quarter 2018, which includes the total increase in the base capital cost forecast and construction contingency estimate.

On August 31, 2018, Georgia Power filed its nineteenth VCM report with the Georgia PSC, which requested approval of $578 million of construction capital costs incurred from January 1, 2018 through June 30, 2018. On February 19, 2019, the Georgia PSC approved the nineteenth VCM, but deferred approval of $51.6 million of expenditures related to Georgia Power's portion of an administrative claim filed in the Westinghouse bankruptcy proceedings. Through the nineteenth VCM, the Georgia PSC has approved total construction capital costs incurred through June 30, 2018 of $5.4 billion (before $1.7 billion of payments received under the Guarantee Settlement Agreement and approximately $188 million in related Customer Refunds). In addition, the staff of the Georgia PSC requested, and Georgia Power agreed, to file its twentieth VCM report concurrently with the twenty-first VCM report by August 31, 2019.

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

DOE Financing

At December 31, 2018, 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. In September 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. In September 2018, the DOE extended the conditional commitment to March 31, 2019. Any further extension must be 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 8 under "Long-term Debt – DOE Loan Guarantee Borrowings" for additional information, including applicable covenants, events of default, mandatory prepayment events (including any decision not to continue construction of Plant Vogtle Units 3 and 4), and conditions to borrowing.

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

Mississippi Power

Regulatory Assets and Liabilities

Regulatory assets and (liabilities) reflected in the balance sheets of Mississippi Power at December 31, 2018 and 2017 relate to:

	2018	2017	Note
		(in millions)	
Retiree benefit plans – regulatory assets	**$ 171**	$ 174	(a)
Asset retirement obligations	**143**	95	(b)
Kemper County energy facility assets, net	**69**	88	(c)
Remaining net book value of retired assets	**41**	44	(d)
Property tax	**44**	43	(e)
Deferred charges related to income taxes	**34**	36	(b)
Plant Daniel Units 3 and 4	**36**	36	(f)
ECO carryforward	**26**	26	(g)
Other regulatory assets	**28**	28	(h)
Deferred credits related to income taxes	**(377)**	(377)	(i)
Other cost of removal obligations	**(185)**	(178)	(b)
Property damage	**(56)**	(57)	(j)
Other regulatory liabilities	**(9)**	—	(k)
Total regulatory assets (liabilities), net	**$ (35)**	$ (42)	

Note: Unless otherwise noted, the recovery and amortization periods for these regulatory assets and (liabilities) are approved by the Mississippi PSC and are as follows:

(a) Recovered and amortized over the average remaining service period which may range up to 15 years. See Note 11 for additional information.

(b) Asset retirement and other cost of removal obligations and deferred charges related to income taxes are generally recovered over the related property lives, which may range up to 48 years. Asset retirement and other cost of removal obligations will be settled and trued up upon completion of removal activities over a period to be determined by the Mississippi PSC.

(c) Includes $91 million of regulatory assets and $22 million of regulatory liabilities. The retail portion includes $75 million of regulatory assets and $22 million of regulatory liabilities that are being recovered in rates over an eight-year period through 2025 and a six-year period through 2023, respectively. Recovery of the wholesale portion of the regulatory assets in the amount of $16 million is expected to be determined in a settlement agreement with wholesale customers in 2019. For additional information, see "Kemper County Energy Facility – Rate Recovery – Kemper Settlement Agreement" herein.

(d) Retail portion includes approximately $26 million being recovered over a five-year period through 2021 and 2022 for Plant Watson and Plant Greene County, respectively. Recovery of the wholesale portion of approximately $15 million is expected to be determined in a settlement agreement with wholesale customers in 2019.

(e) Recovered through the ad valorem tax adjustment clause over a 12-month period beginning in April of the following year. See "Ad Valorem Tax Adjustment" herein 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) Generally recovered through the ECO Plan clause in the year following the deferral. See "Environmental Compliance Plan" herein.

(h) Comprised of $9 million related to vacation pay, $8 million related to loss on reacquired debt, and other miscellaneous assets. These costs are recorded and recovered or amortized over periods which may range up to 50 years. This amount also includes fuel-hedging assets 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.

(i) Includes excess deferred income taxes primarily associated with Tax Reform Legislation of $377 million, of which $266 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 $111 million related to unprotected (not subject to normalization). The unprotected portion associated with the Kemper County energy facility is $46 million, of which $33 million is being amortized over eight years through 2025 for retail and the amortization of $15 million is expected to be determined in a settlement agreement with wholesale customers in 2019. Mississippi Power also has $9 million of excess deferred income tax benefits associated with the System Restoration Rider being amortized over an eight-year period through 2025. Amortization of the remaining portions of the unprotected deferred income taxes associated with the Tax Reform Legislation are expected to be determined in Mississippi Power's next base rate proceeding, which is scheduled to be filed in the fourth quarter 2019 (Mississippi Power 2019 Base Rate Case). See "Kemper County Energy Facility" and "FERC Matters – Mississippi Power – Municipal and Rural Associations Tariff" herein and Note 10 for additional information.

(j) For additional information, see "System Restoration Rider" herein.

(k) Comprised of numerous immaterial components including deferred income tax credits and other miscellaneous liabilities that are recorded and refunded or amortized generally over periods not exceeding one year.

Operations Review

In August 2018, the Mississippi PSC began an operations review of Mississippi Power, for which the final report is expected prior to the conclusion of the Mississippi Power 2019 Base Rate Case. Mississippi Power expects that the review will include, but not be limited to, a comparative analysis of its costs, its cost recovery framework, and ways in which it may streamline management operations for the reasonable benefit of ratepayers. The ultimate outcome of this matter cannot be determined at this time.

Performance Evaluation Plan

Mississippi Power's retail base rates generally 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, Mississippi Power 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 Mississippi Power's PEP lookback filing for 2011. In 2013, the MPUS contested Mississippi Power's PEP lookback filing for 2012, which indicated a refund due to customers of $5 million. In 2014 through 2018, Mississippi Power submitted its annual PEP lookback filings for the prior years, which for each of 2013, 2014, and 2017 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 in November 2017, Mississippi Power 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, Mississippi Power revised its annual projected PEP filing for 2018 to reflect the impacts of the Tax Reform Legislation. The revised filing requested an increase of $26 million in annual revenues, based on a performance adjusted ROE of 9.33% and an increased equity ratio of 55%. On July 27, 2018, Mississippi Power and the MPUS entered into a settlement agreement, which was approved by the Mississippi PSC on August 7, 2018, with respect to the 2018 PEP filing and all unresolved PEP filings for prior years (PEP Settlement Agreement). Rates under the PEP Settlement Agreement became effective with the first billing cycle of September 2018. The PEP Settlement Agreement provides for an increase of approximately $21.6 million in annual base retail revenues, which excludes certain compensation costs contested by the MPUS, as well as approximately $2 million which was subsequently approved for recovery through the 2018 Energy Efficiency Cost Rider as discussed below. Under the PEP Settlement Agreement, Mississippi Power is deferring the contested compensation costs for 2018 and 2019 as a regulatory asset, which totaled $4 million as of December 31, 2018 and is included in other regulatory assets, deferred on the balance sheet. The Mississippi PSC is currently expected to rule on the appropriate treatment for such costs in connection with the Mississippi Power 2019 Base Rate Case. The ultimate outcome of this matter cannot be determined at this time.

Pursuant to the PEP Settlement Agreement, Mississippi Power's performance-adjusted allowed ROE is 9.31% and its allowed equity ratio is capped at 51%, pending further review by the Mississippi PSC. In lieu of the requested equity ratio increase, Mississippi Power retained $44 million of excess accumulated deferred income taxes resulting from the Tax Reform Legislation until the conclusion of the Mississippi Power 2019 Base Rate Case. Further, Mississippi Power agreed to seek equity contributions sufficient to restore its equity ratio to 50% by December 31, 2018. Since Mississippi Power's actual average equity ratio for 2018 was more than 1% lower than the 50% target, Mississippi Power deferred the corresponding difference in its revenue requirement of approximately $4 million as a regulatory liability for resolution in the Mississippi Power 2019 Base Rate Case. Pursuant to the PEP Settlement Agreement, PEP proceedings are suspended until after the conclusion of the Mississippi Power 2019 Base Rate Case and Mississippi Power is not required to make any PEP filings for regulatory years 2018, 2019, and 2020. The PEP Settlement Agreement also resolved all open PEP filings with no change to customer rates. As a result, in the third quarter 2018, Mississippi Power recognized revenues of $5 million previously reserved in connection with the 2012 PEP lookback filing.

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 May 8, 2018, the Mississippi PSC issued an order approving Mississippi Power's revised annual projected Energy Efficiency Cost Rider 2018 compliance filing, which increased annual retail revenues by approximately $3 million effective with the first billing cycle for June 2018.

On February 5, 2019, the Mississippi PSC issued an order approving Mississippi Power's Energy Efficiency Cost Rider 2019 compliance filing, which included a slight decrease in annual retail revenues, effective with the first billing cycle in March 2019.

Environmental Compliance Overview Plan

In accordance with a 2011 accounting order from the Mississippi PSC, Mississippi Power 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 the fuel conversion of 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 Mississippi Power's financial statements.

In August 2016, the Mississippi PSC approved Mississippi Power'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.

In May 2017, the Mississippi PSC approved Mississippi Power'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, plus carrying costs, of related revenue requirements in excess of the 2% maximum was deferred for inclusion in the 2018 filing.

On February 14, 2018, Mississippi Power submitted its ECO Plan filing for 2018, including the effects of the 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.

On August 3, 2018, Mississippi Power and the MPUS entered into the ECO Settlement Agreement, which provides for an increase of approximately $17 million in annual base retail revenues and was approved by the Mississippi PSC on August 7, 2018. Rates under the ECO Settlement Agreement became effective with the first billing cycle of September 2018 and will continue in effect until modified by the Mississippi PSC. These revenues are expected to be sufficient to recover the costs included in Mississippi Power's request for 2018, as well as the remaining deferred amounts, totaling $26 million at December 31, 2018, along with the related carrying costs. In accordance with the ECO Settlement Agreement, ECO Plan proceedings are suspended until after the conclusion of the Mississippi Power 2019 Base Rate Case and Mississippi Power is not required to make any ECO Plan filings for 2018, 2019, and 2020, with any necessary adjustments to be reflected in the Mississippi Power 2019 Base Rate Case. The ECO Settlement Agreement contains the same terms as the PEP Settlement Agreement described herein with respect to allowed ROE and equity ratio. At December 31, 2018, Mississippi Power has recorded $2 million in other regulatory liabilities, deferred on the balance sheet related to the actual December 31, 2018 average equity ratio differential from target applicable to the ECO Plan.

Fuel Cost Recovery

Mississippi Power establishes, annually, a retail fuel cost recovery factor that is approved by the Mississippi PSC. Mississippi Power is required to file for an adjustment to the retail fuel cost recovery factor annually. In January 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 $55 million. On January 16, 2018, the Mississippi PSC approved the 2018 retail fuel cost recovery factor, effective February 2018 through January 2019, which resulted in an annual revenue increase of $39 million. At December 31, 2018, the amount of over recovered retail fuel costs included in the balance sheet in other accounts payable was approximately $8 million compared to $6 million under recovered at December 31, 2017. On January 10, 2019, the Mississippi PSC approved the 2019 retail fuel cost recovery factor, effective February 2019, which results in a $35 million decrease in annual revenues as a result of lower expected fuel costs.

Mississippi Power'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 Southern Company's or Mississippi Power's revenues or net income but will affect operating cash flows.

Ad Valorem Tax Adjustment

Mississippi Power establishes annually an ad valorem tax adjustment factor that is approved by the Mississippi PSC to collect the ad valorem taxes paid by Mississippi Power. In 2018, 2017, and 2016, the Mississippi PSC approved Mississippi Power's annual ad valorem tax adjustment factor filing, which included a rate increase of 0.8%, or $7 million, in 2018, a rate increase of 0.85%, or $8 million, in 2017, and a rate decrease of 0.07%, or $1 million, in 2016.

System Restoration Rider

Mississippi Power carries insurance for the cost of certain types of damage to generation plants and general property. However, Mississippi Power 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, Mississippi Power 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 Mississippi Power 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 Mississippi Power 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 Mississippi Power 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. Mississippi Power made retail accruals of $1 million, $3 million, and $4 million for 2018, 2017, and 2016, respectively. Mississippi Power also accrued $0.3 million annually in 2018, 2017, and 2016 for the wholesale jurisdiction. As of December 31, 2018, the property damage reserve balances were $55 million and $1 million for retail and wholesale, respectively.

Based on Mississippi Power's annual SRR rate filings, the SRR rate was zero for all years presented and Mississippi Power accrued $2 million, $4 million, and $3 million to the property damage reserve in 2018, 2017, and 2016, respectively. The SRR rate filings were suspended by the Mississippi PSC for review for a period not to exceed 120 days from their respective filing dates, after which the filings became effective.

In January 2017, a tornado caused extensive damage to Mississippi Power's transmission and distribution infrastructure. The cost of storm damage repairs was approximately $9 million. A portion of these costs was charged to the retail property damage reserve and addressed in the 2018 SRR rate filing.

Kemper County Energy Facility

Overview

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

Schedule and Cost Estimate

In 2012, the Mississippi PSC issued an order (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 combined cycle and associated common facilities portions of the Kemper County energy facility were dedicated as Plant Ratcliffe on April 27, 2018.

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. The order established a new docket for the purpose 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 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 received in April 2016. 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 gasification 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.

In 2018, Mississippi Power recorded pre-tax charges to income of $37 million ($27 million after tax), primarily resulting from the abandonment and related closure activities and ongoing period costs, net of sales proceeds, for the mine and gasifier-related assets at the Kemper County energy facility. In addition, Mississippi Power recorded a credit to earnings of $95 million in the fourth quarter 2018 primarily resulting from the reduction of a valuation allowance for a state income tax NOL carryforward associated with the Kemper County energy facility. Additional closure costs for the mine and gasifier-related assets, currently estimated at up to $10 million pre-tax (excluding salvage, net of dismantlement costs), may be incurred through the first half of 2020. In addition, period costs, including, but not limited to, costs for compliance and safety, ARO accretion, and property taxes for the mine and gasifier-related assets, are estimated to total $11 million in 2019 and $2 million to $4 million annually in 2020 through 2023. Mississippi Power is currently evaluating its options regarding the final disposition of the CO_2 pipeline, including removal of the pipeline. This evaluation is expected to be complete later in 2019. If Mississippi Power ultimately decides to remove the CO_2 pipeline, the cost of removal would have a material impact on Mississippi Power's financial statements and could have a material impact on Southern Company's financial statements. The ultimate outcome of these matters cannot be determined at this time.

See Note 10 for additional information.

Rate Recovery

Kemper Settlement Agreement

In 2015, the Mississippi PSC issued an order (In-Service Asset Rate Order) regarding the Kemper County energy facility assets that were commercially operational and 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 which went into effect on December 17, 2015.

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), which resolved all cost recovery issues, modified the CPCN to limit the Kemper County energy facility to natural gas combined cycle operation, and provided for an annual revenue requirement of approximately $99.3 million for costs related to the Kemper County energy facility, which included the impact of the 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 reflect a reduction of approximately $26.8 million annually, effective with the first billing cycle of April 2018, and include no recovery for costs associated with the gasifier portion of the Kemper County energy facility in 2018 or at any future date.

Reserve Margin Plan

On August 6, 2018, Mississippi Power filed its proposed Reserve Margin Plan (RMP), as required by the Mississippi PSC's order in the Kemper Settlement Docket. Under the RMP, Mississippi Power proposed alternatives that would reduce its reserve margin,

with the most economic of the alternatives being the two-year and seven-year acceleration of the retirement of Plant Watson Units 4 and 5, respectively, to the first quarter 2022 and the four-year acceleration of the retirement of Plant Greene County Units 1 and 2 to the third quarter 2021 and the third quarter 2022, respectively, in order to lower or avoid operating costs. The Plant Greene County unit retirements would require the completion by Alabama Power of proposed transmission and system reliability improvements, as well as agreement by Alabama Power. The RMP filing also states that, in the event the Mississippi PSC ultimately approves an alternative that includes an accelerated retirement, Mississippi Power would require authorization to defer in a regulatory asset for future recovery the remaining net book value of the units at the time of retirement. A decision by the Mississippi PSC that does not include recovery of the remaining book value of any generating units retired could have a material impact on Mississippi Power's and Southern Company's financial statements. The ultimate outcome of this matter cannot be determined at this time.

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. As a result of the abandonment of the Kemper IGCC, final mine reclamation began in 2018 and is expected to be substantially completed in 2020, with monitoring expected to continue through 2027. See Note 6 and Note 7 under "Mississippi Power" for additional information.

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. The agreement with Denbury was terminated in December 2018 and did not have a material impact on Southern Company's or Mississippi Power's results of operations. Mississippi Power is currently evaluating its options regarding the final disposition of the CO_2 pipeline, including removal of the pipeline. This evaluation is expected to be complete later in 2019. If Mississippi Power ultimately decides to remove the CO_2 pipeline, the cost of removal would have a material impact on Mississippi Power's financial statements and could have a material impact on Southern Company's financial statements. The ultimate outcome of this matter cannot be determined at this time.

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. Through December 31, 2018, Mississippi Power received total DOE grants of $387 million, of which $382 million reduced the construction costs of the Kemper County energy facility and $5 million reimbursed Mississippi Power for expenses associated with DOE reporting. On December 12, 2018, Mississippi Power filed with the DOE its request for property closeout certification under the contract related to the grants received. Mississippi Power and the DOE are currently in discussions regarding the requested closeout and property disposition, which may require payment to the DOE for a portion of certain property that is to be retained by Mississippi Power. The ultimate outcome of this matter cannot be determined at this time; however, it could have a material impact on Mississippi Power's financial statements and a significant impact on Southern Company's financial statements.

Southern Company Gas

Regulatory Assets and Liabilities

Regulatory assets and (liabilities) reflected in the balance sheets of Southern Company Gas at December 31, 2018 and 2017 relate to:

	2018	2017	Note
	(in millions)		
Environmental remediation	**$ 311**	$ 410	(a,b)
Retiree benefit plans	**161**	270	(a,c)
Long-term debt fair value adjustment	**121**	138	(d)
Under recovered regulatory clause revenues	**90**	98	(e)
Other regulatory assets	**59**	79	(f)
Other cost of removal obligations	**(1,585)**	(1,646)	(g)
Deferred income tax credits	**(940)**	(1,063)	(g,i)
Over recovered regulatory clause revenues	**(43)**	(144)	(e)
Other regulatory liabilities	**(46)**	(21)	(h)
Total regulatory assets (liabilities), net	**$ (1,872)**	$ (1,879)	

Note: Unless otherwise noted, the recovery and amortization periods for these regulatory assets and (liabilities) have been approved or accepted by the relevant state PSC or other regulatory body and 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 11 for additional information.

(d) Recovered over the remaining life of the original debt issuances, which range up to 20 years.

(e) Recorded and recovered or amortized over periods generally not exceeding seven years. In addition to natural gas cost recovery mechanisms, the natural gas distribution utilities are authorized to utilize 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.

(f) Comprised of several components including unamortized loss on reacquired debt, weather normalization, franchise gas, deferred depreciation, and financial instrument-hedging assets, which are recovered or amortized 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 amounts to be refunded to customers as a result of the Tax Reform Legislation, energy efficiency programs, and unamortized bond issuance costs and financial instrument-hedging liabilities which are recovered or amortized over periods generally not exceeding 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. See "Rate Proceedings" herein for additional information regarding customer refunds resulting from the Tax Reform Legislation.

(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 is expected to be determined by the applicable state regulatory agencies in future rate proceedings. See "Rate Proceedings" herein and Note 10 for additional details.

Infrastructure Replacement Programs and Capital Projects

In addition to capital expenditures recovered through base rates by each of the natural gas distribution utilities, Nicor Gas and Virginia Natural Gas have separate rate riders that provide timely recovery of capital expenditures for specific infrastructure replacement programs. Descriptions of the infrastructure replacement programs and capital projects at the natural gas distribution utilities follow:

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, subject to annual review. In conjunction with the base rate case order issued by the Illinois Commission on January 31, 2018, Nicor Gas is recovering program costs incurred prior to December 31, 2017 through base rates. Nicor Gas has requested that the program costs incurred

subsequent to December 31, 2017, which are currently being recovered through a separate rider, be addressed in the base rate case filed November 9, 2018. See "Rate Proceedings" herein for additional information.

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. In 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 in December 2017, Virginia Natural Gas is recovering program costs incurred prior to September 1, 2017 through base rates. Program costs incurred subsequent to September 1, 2017 are currently recovered through a separate rider and are subject to future base rate case proceedings.

Atlanta Gas Light

GRAM

In February 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 including the Integrated Vintage Plastic Replacement Program to replace aging plastic pipe and the Integrated System Reinforcement Program to upgrade Atlanta Gas Light's distribution system and LNG facilities in Georgia continue under GRAM and the recovery of and return on the infrastructure program investments are included in annual base rate adjustments. The Georgia PSC reviews Atlanta Gas Light's performance annually under GRAM. See Rate Proceedings" herein for additional information.

Pursuant to the GRAM approval, Atlanta Gas Light and the staff of the Georgia PSC agreed to a variation of the Integrated Customer Growth Program to extend pipeline facilities to serve customers in areas without pipeline access and create new economic development opportunities in Georgia, which was formerly part of the 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.

The orders for the STRIDE program 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 program, net of any related cost savings. The regulatory asset represents incurred program costs that will be collected through GRAM. 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.

PRP

In 2015, 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 under recovered PRP balance of $144 million and the estimated amounts to be earned under the program through 2025. The unrecovered balance is the result of the continued revenue requirement earned under the program offset by the existing and incremental PRP surcharges. The under recovered balance at December 31, 2018 was $171 million, including $95 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 "Rate Proceedings" and "Unrecognized Ratemaking Amounts" herein for additional information.

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 were included in base rates in 2018. In 2017, Atlanta Gas Light recovered $20 million from the settlement of contractor litigation claims and recovered an additional $7 million from the

final settlement of contractor litigation claims during the first quarter 2018. Mitigation costs recovered through the legal process are retained by Atlanta Gas Light.

Natural Gas Cost Recovery

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 Southern Company's or Southern Company Gas' revenues or net income, but will affect cash flows.

Rate Proceedings

Nicor Gas

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%.

On April 19, 2018, the Illinois Commission approved Nicor Gas' variable income tax adjustment rider. This rider provides for refund or recovery of changes in income tax expense that result from income tax rates that differ from those used in Nicor Gas' last rate case. Customer refunds, via bill credits, related to the impacts of the Tax Reform Legislation from January 25, 2018 through May 4, 2018 began on July 1, 2018 and are expected to conclude in the second quarter 2019.

On May 2, 2018, the Illinois Commission approved Nicor Gas' rehearing request for revised base rates to incorporate the reduction in the federal income tax rate as a result of the Tax Reform Legislation. The resulting decrease of approximately $44 million in annual base rate revenues became effective May 5, 2018. Nicor Gas' previously-authorized capital structure and ROE of 9.80% were not addressed in the rehearing and remain unchanged.

On November 9, 2018, Nicor Gas filed a general base rate case with the Illinois Commission requesting a $230 million increase in annual base rate revenues. The requested increase is based on a projected test year for the 12-month period ending September 30, 2020, a ROE of 10.6%, and an increase in the equity ratio from 52.0% to 54.0% to address the negative cash flow and credit metric impacts of the Tax Reform Legislation. The Illinois Commission is expected to rule on the requested increase within the 11-month statutory time limit, after which rate adjustments will be effective. The ultimate outcome of this matter cannot be determined at this time.

Atlanta Gas Light

On February 23, 2018, Atlanta Gas Light revised its annual base rate filing to reflect the impacts of the Tax Reform Legislation and requested a $16 million rate reduction in 2018. On May 15, 2018, the Georgia PSC approved a stipulation for Atlanta Gas Light's annual base rates to remain at the 2017 level for 2018 and 2019, with customer credits of $8 million in each of July 2018 and October 2018 to reflect the impacts of the Tax Reform Legislation. The Georgia PSC maintained Atlanta Gas Light's previously authorized earnings band based on a ROE between 10.55% and 10.95% and increased the allowed equity ratio by 4% to an equity ratio of 55% to address the negative cash flow and credit metric impacts of the Tax Reform Legislation. Additionally, Atlanta Gas Light is required to file a traditional base rate case on or before June 1, 2019 for rates effective January 1, 2020.

Atlanta Gas Light's recovery of the previously unrecovered PRP revenue through 2014, as well as the mitigation costs associated with the PRP that were not previously included in its rates, were included in GRAM. In connection with the GRAM approval, the last monthly PRP surcharge increase became effective March 1, 2017.

Virginia Natural 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 December 17, 2018, the Virginia Commission approved Virginia Natural Gas' annual information form filing, which reduced annual base rates by $14 million effective January 1, 2019 due to lower tax expense as a result of the lower corporate income tax rate and the impact of the flowback of excess deferred income taxes. This approval also requires Virginia Natural Gas to issue

customer refunds, via bill credits, for the entire $14 million which was deferred as a regulatory liability, current, on the balance sheet at December 31, 2018. These customer refunds are expected to be completed in the first quarter 2019.

energySMART

The Illinois Commission approved Nicor Gas' energySMART program, which includes energy efficiency program offerings and therm reduction goals. Through December 31, 2017, Nicor Gas spent $107 million of the initial authorized expenditure of $113 million. A new program began on January 1, 2018, with an additional authorized expenditure of $160 million through 2021. Through December 31, 2018, Nicor Gas had spent $29 million.

Unrecognized Ratemaking Amounts

The following table illustrates Southern Company Gas' 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 regulatory infrastructure programs. These amounts will be recognized as revenues in Southern Company Gas' financial statements in the periods they are billable to customers, the majority of which will be recovered by 2025.

	December 31, 2018	December 31, 2017
	(in millions)	
Atlanta Gas Light	**$ 95**	$ 104
Virginia Natural Gas	**11**	11
Nicor Gas	**4**	2
Total	**$ 110**	$ 117

FERC Matters

Open Access Transmission Tariff

On May 10, 2018, AMEA and Cooperative Energy filed with the FERC a complaint against SCS and the traditional electric operating companies claiming that the current 11.25% base ROE used in calculating the annual transmission revenue requirements of the traditional electric operating companies' open access transmission tariff is unjust and unreasonable as measured by the applicable FERC standards. The complaint requested that the base ROE be set no higher than 8.65% and that the FERC order refunds for the difference in revenue requirements that results from applying a just and reasonable ROE established in this proceeding upon determining the current ROE is unjust and unreasonable. On June 18, 2018, SCS and the traditional electric operating companies filed their response challenging the adequacy of the showing presented by the complainants and offering support for the current ROE. On September 6, 2018, the FERC issued an order establishing a refund effective date of May 10, 2018 in the event a refund is due and initiating an investigation and settlement procedures regarding the current base ROE. Through December 31, 2018, the estimated maximum potential refund is not expected to be material to Southern Company's or the traditional electric operating companies' results of operations or cash flows. The ultimate outcome of this matter cannot be determined at this time.

Mississippi Power

Municipal and Rural Associations Tariff

Mississippi Power 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 2016, Mississippi Power 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 included (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, which totaled approximately $22 million through the suspension of Kemper IGCC start-up activities.

Mississippi Power expects to reach a subsequent settlement agreement with its wholesale customers and will make a filing with the FERC during the first quarter 2019. The settlement agreement is intended to be consistent with the Kemper Settlement Agreement, including the impact of the Tax Reform Legislation. The ultimate outcome of this matter cannot be determined at this time.

In September 2017, Mississippi Power and Cooperative Energy executed a Shared Service Agreement (SSA), as part of the MRA tariff, under which Mississippi Power 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 in October 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 Mississippi Power'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 Mississippi Power's revenues is not expected to be significant through 2020.

Fuel Cost Recovery

Mississippi Power has a wholesale MRA and a Market Based (MB) fuel cost recovery factor. Effective with the first billing cycle for January 2018, fuel rates increased $11 million annually for wholesale MRA customers and $1 million annually for wholesale MB customers. Effective January 1, 2019, the wholesale MRA fuel rate decreased $16 million annually and the wholesale MB fuel rate decreased by an immaterial amount. At December 31, 2018, over recovered wholesale MRA fuel costs included in other regulatory liabilities, current on the balance sheet were approximately $6 million compared to an immaterial amount at December 31, 2017. Under recovered wholesale MB fuel costs included in the balance sheets were immaterial at December 31, 2018 and 2017.

Mississippi Power'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 Mississippi Power's revenues or net income, but will affect cash flow.

Southern Company Gas

At December 31, 2018, Southern Company Gas was involved in two gas pipeline construction projects. 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 January 19, 2018, the PennEast Pipeline received FERC approval. Work continues with state and federal agencies to obtain the required permits to begin construction. Any material delays may impact forecasted capital expenditures and the expected in-service date.

In October 2017, the Atlantic Coast Pipeline received FERC approval. This joint venture has experienced challenges to its permits since construction began in 2018. During the third and fourth quarters 2018, a FERC stop work order, together with delays in obtaining permits necessary for construction and construction delays due to judicial actions, impacted the cost and schedule for the project. As a result, total project cost estimates have increased from between $6.0 billion and $6.5 billion to between $7.0 billion and $7.8 billion, excluding financing costs. Southern Company Gas' share of the total project costs is 5% and Southern Company Gas' investment at December 31, 2018 totaled $83 million. The operator of the joint venture currently expects to achieve a late 2020 in-service date for at least key segments of the Atlantic Coast Pipeline, while the remainder may extend into early 2021. Southern Company Gas has evaluated the recoverability of its investment and determined there was no impairment as of December 31, 2018. Abnormal weather, work delays (including due to judicial or regulatory action), and other conditions may result in additional cost or schedule modifications, which could result in an impairment of Southern Company Gas' investment and could have a material impact on Southern Company's and Southern Company Gas' financial statements.

The ultimate outcome of these matters cannot be determined at this time. See Notes 7 and 9 under "Southern Company Gas – Equity Method Investments" and "Guarantees," respectively, for additional information on these pipeline projects.

3. CONTINGENCIES

General Litigation Matters

Each registrant is 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 laws and regulations governing air, water, land, and protection of other natural resources. Litigation over environmental issues and claims of various types, including property damage, personal injury, common law nuisance, and citizen enforcement of environmental laws and regulations 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 each registrant and any 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 such registrant's financial statements.

Southern Company

In January 2017, a putative 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. In June 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. In July 2017, the defendants filed a motion to dismiss the plaintiffs' amended complaint with prejudice, to which the plaintiffs filed an opposition in September 2017. On March 29, 2018, the U.S. District Court for the Northern District of Georgia, Atlanta Division, issued an order granting, in part, the defendants' motion to dismiss. The court dismissed certain claims against certain officers of Southern Company and Mississippi Power and dismissed the allegations related to a number of the statements that plaintiffs challenged as being false or misleading. On April 26, 2018, the defendants filed a motion for reconsideration of the court's order, seeking dismissal of the remaining claims in the lawsuit. On August 10, 2018, the court denied the motion for reconsideration and denied a motion to certify the issue for interlocutory appeal.

In February 2017, Jean Vineyard filed a shareholder derivative lawsuit and, in May 2017, Judy Mesirov filed a shareholder derivative lawsuit, each 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. In August 2017, these two shareholder derivative lawsuits were consolidated in the U.S. District Court for the Northern District of Georgia. The complaints allege that the defendants caused Southern Company to make false or misleading statements regarding the Kemper County energy facility cost and schedule. Further, the complaints allege that the defendants were unjustly enriched and caused the waste of corporate assets and also allege that the individual defendants violated their fiduciary duties. Each plaintiff seeks to recover, on behalf of Southern Company, unspecified actual damages and, on each plaintiff's own behalf, attorneys' fees and costs in bringing the lawsuit. Each plaintiff also seeks certain changes to Southern Company's corporate governance and internal processes. On April 25, 2018, the court entered an order staying this lawsuit until 30 days after the resolution of any dispositive motions or any settlement, whichever is earlier, in the putative securities class action.

In May 2017, Helen E. Piper Survivor's Trust filed a shareholder derivative lawsuit in the Superior Court of Gwinnett County, State 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 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. The 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. The 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. The plaintiff also seeks certain unspecified changes to Southern Company's corporate governance and internal processes. On May 4, 2018, the court entered an order staying this lawsuit until 30 days after the resolution of any dispositive motions or any settlement, whichever is earlier, in the putative securities class action.

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.

Alabama Power

On March 2, 2018, the Alabama Department of Environmental Management (ADEM) issued proposed administrative orders assessing a penalty of $1.25 million to Alabama Power for unpermitted discharge of fluids and/or pollutants to groundwater at five electric generating plants. The orders were finalized and Alabama Power paid the penalty on September 27, 2018. This matter is now concluded.

Georgia Power

In 2011, plaintiffs filed a putative class action against Georgia Power in the Superior Court of Fulton County, Georgia alleging that Georgia Power's collection in rates of amounts for municipal franchise fees (which fees are paid to municipalities) exceeded the amounts allowed in orders of the Georgia PSC and alleging certain state tort law claims. In 2016, the Georgia Court of Appeals reversed the trial court's previous dismissal of the case and remanded the case to the trial court. Georgia Power filed a petition for writ of certiorari with the Georgia Supreme Court, which was granted in August 2017. On June 18, 2018, the Georgia Supreme Court affirmed the judgment of the Georgia Court of Appeals and remanded the case to the trial court for further proceedings. Following a motion by Georgia Power, on February 13, 2019, the Superior Court of Fulton County entered an order staying this lawsuit for 60 days and ordered the parties to submit petitions to the Georgia PSC within 20 days for a declaratory ruling to address certain terms the court previously held were ambiguous as used in the Georgia PSC's orders. The order entered by the Superior Court of Fulton County also conditionally certified the proposed class. Georgia Power believes the plaintiffs' claims have no merit and will continue to vigorously defend itself in this matter. The amount of any possible losses cannot be calculated at this time because, among other factors, it is unknown whether conditional class certification will be upheld and the ultimate composition of any class; and whether any losses would be subject to recovery from any municipalities. The ultimate outcome of this matter cannot be determined at this time.

Mississippi Power

In 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 to include, among other things, Southern Company as a defendant. The individual plaintiff alleged that Mississippi Power and Southern Company violated the Mississippi Unfair Trade Practices Act. All plaintiffs 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 unjustly enriched Mississippi Power and Southern Company. The plaintiffs sought unspecified actual damages and punitive damages; asked the Circuit Court to appoint a receiver to oversee, operate, manage, and otherwise control all affairs relating to the Kemper County energy facility; asked 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 sought attorney's fees, costs, and interest. The plaintiffs also sought an injunction to prevent any Kemper County energy facility costs from being charged to customers through electric rates. In June 2017, the Circuit Court ruled in favor of motions by Southern Company and Mississippi Power and dismissed the case. In July 2017, the plaintiffs filed notice of an appeal. On July 13, 2018, Mississippi Power and Southern Company reached a settlement agreement with the plaintiffs and the plaintiffs' appeal was dismissed with prejudice. The settlement had no material impact on Southern Company's or Mississippi Power's financial statements.

On May 18, 2018, Southern Company and Mississippi Power received a notice of dispute and arbitration demand filed by Martin Product Sales, LLC (Martin) based on two agreements, both related to Kemper IGCC byproducts for which Mississippi Power provided termination notices in September 2017. Martin alleges breach of contract, breach of good faith and fair dealing, fraud and misrepresentation, and civil conspiracy and makes a claim for damages in the amount of approximately $143 million, as well as additional unspecified damages, attorney's fees, costs, and interest. In the first quarter 2019, Mississippi Power and Southern Company filed motions to dismiss. Southern Company and Mississippi Power believe this legal challenge has no merit; however, an adverse outcome in this proceeding could have a material impact on Southern Company's and Mississippi Power's results of operations, financial condition, and liquidity. Southern Company and Mississippi Power will vigorously defend themselves in this matter, the ultimate outcome of which cannot be determined at this time.

On November 21, 2018, Ray C. Turnage and 10 other individual plaintiffs filed a putative class action complaint against Mississippi Power and the three current members of the Mississippi PSC in the U.S. District Court for the Southern District of Mississippi. Mississippi Power received Mississippi PSC approval in 2013 to charge a mirror CWIP rate premised upon including

in its rate base pre-construction and construction costs for the Kemper IGCC prior to placing the Kemper IGCC into service. The Mississippi Supreme Court reversed that approval and ordered Mississippi Power to refund the amounts paid by customers under the previously-approved mirror CWIP rate. The plaintiffs allege that the initial approval process, and the amount approved, were improper. They also allege that Mississippi Power underpaid customers in the refund process because it applied the wrong interest rate to the payments. The plaintiffs seek to recover, on behalf of themselves and their putative class, actual damages, punitive damages, pre-judgment interest, post-judgment interest, attorney's fees, and costs. Mississippi Power believes this legal challenge has no merit; however, an adverse outcome in this proceeding could have a material impact on Mississippi Power's results of operations, financial condition, and liquidity. Mississippi Power will vigorously defend itself in this matter, the ultimate outcome of which cannot be determined at this time.

Southern Power

Southern Power indirectly owns a 51% membership interest in RE Roserock LLC (Roserock), the owner of the Roserock facility in Pecos County, Texas. Prior to the facility being placed in service in November 2016, certain solar panels were damaged during installation by the construction contractor, McCarthy Building Companies, Inc. (McCarthy), and certain solar panels were damaged by a hail event that also occurred during construction. In connection therewith, Southern Power is withholding payments of approximately $26 million from the construction contractor, which has placed a lien on the Roserock facility for the same amount. In May 2017, Roserock filed a lawsuit in the state district court in Pecos County, Texas, (State Court lawsuit) 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 the hail storm and McCarthy's installation practices. On June 1, 2018, the court in the State Court lawsuit granted Roserock's motion for partial summary judgment, finding that the insurers were in breach of contract and in violation of the Texas Insurance Code for failing to pay any monies owed for the hail claim. In addition to the State Court lawsuit, lawsuits were filed between Roserock and McCarthy, as well as other parties, and that litigation has been consolidated in the U.S. District Court for the Western District of Texas. Southern Power intends to vigorously pursue and defend these matters, the ultimate outcome of which cannot be determined at this time.

Southern Company Gas

Nicor Energy Services Company, doing business as Pivotal Home Solutions, formerly a wholly-owned subsidiary of Southern Company Gas, was a defendant in a putative class action initially filed in 2017 in the state court in Indiana. The plaintiffs purported to represent a class of the customers who purchased products from Nicor Energy Services Company and alleged that the marketing, sale, and billing of the products violated the Indiana Consumer Fraud and Deceptive Business Practices Act, constituting common law fraud and resulting in unjust enrichment of these entities. In 2018, Nicor Energy Services Company was named in a second class action filed in the state court of Ohio asserting nearly identical allegations and legal claims. The plaintiffs sought, on behalf of the classes they purported to represent, actual and punitive damages, interest costs, attorney fees, and injunctive relief. To facilitate the sale of Pivotal Home Solutions, Southern Company Gas retained most of the financial responsibility for these lawsuits following the completion of the sale. On June 12, 2018, the parties settled these claims and Southern Company Gas recorded an $11 million charge, which is included in other operations and maintenance expenses for the year ended December 31, 2018.

Southern Company Gas is involved in litigation relating to an incident that occurred in one of its prior service territories that resulted in several deaths, injuries, and property damage. Southern Company Gas has resolved all claims for personal injuries or death, but it is continuing to defend litigation seeking to recover alleged property damages. Southern Company Gas has insurance that provides full coverage of the expected financial exposure in excess of $11 million per incident. During the successor period ended December 31, 2016, Southern Company Gas recorded reserves for substantially all of its potential exposure from these cases.

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 and Georgia have each received authority from their respective state PSCs or other applicable state regulatory agencies to recover approved environmental compliance costs through regulatory mechanisms. These regulatory mechanisms are adjusted annually or as necessary within limits approved by the state PSCs or other applicable state regulatory agencies. At

December 31, 2018 and 2017, the environmental remediation liabilities of Alabama Power and Mississippi Power were immaterial.

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. In 2013, the Georgia PSC approved the 2013 ARP including the recovery of approximately $2 million annually through the ECCR tariff. Georgia Power 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 costs recovered through rates is deferred as a regulatory asset or liability. The annual recovery amount is expected to be adjusted as part of the Georgia Power 2019 Base Rate Case and further adjusted in future regulatory proceedings.

Southern Company Gas is subject to environmental remediation liabilities associated with 40 former MGP sites in four different states. Southern Company Gas' accrued environmental remediation liability at December 31, 2018 and 2017 was based on the estimated cost of environmental investigation and remediation associated with known current and former MGP 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 accrued remediation costs.

At December 31, 2018 and 2017, the environmental remediation liability and the balance of under recovered environmental remediation costs were reflected in the balance sheets as follows:

	Southern Company	Georgia Power	Southern Company Gas
		(in millions)	
December 31, 2018:			
Environmental remediation liability:			
Other current liabilities	$ 49	$ 23	$ 26
Accrued environmental remediation	268	—	268
Under recovered environmental remediation costs:			
Other regulatory assets, current	$ 21	$ 2	$ 19
Other regulatory assets, deferred	345	53	292
December 31, 2017:			
Environmental remediation liability:			
Other current liabilities	$ 73	$ 22	$ 46
Accrued environmental remediation(*)	389	—	342
Under recovered environmental remediation costs:			
Other regulatory assets, current	$ 38	$ 2	$ 31
Other regulatory assets, deferred	473	47	379

(*) At December 31, 2017, $85 million of Southern Company Gas' total environmental remediation liability related to Elizabethtown Gas, which was sold on July 1, 2018. See Note 15 under "Southern Company Gas" for more information regarding Southern Company Gas' sale of Elizabethtown Gas.

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 the financial statements of Southern Company, Georgia Power, or Southern Company Gas.

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 Farley, Hatch, and 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, 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, Hatch, and 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. In October 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, Hatch, and 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, the U.S. government disposes of Alabama Power's and Georgia Power's spent nuclear fuel pursuant to its contractual obligations, or alternative storage is otherwise provided. No amounts have been recognized in the financial statements as of December 31, 2018 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, Alabama Power's, or Georgia Power'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.

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 $14.1 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 $138 million per incident for each licensed reactor it operates but not more than an aggregate of $20 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 $275 million and $267 million, respectively, per incident, but not more than an aggregate of $41 million and $40 million, respectively, 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, 2023. See Note 5 under "Joint Ownership Agreements" 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, and have each elected a 12-week deductible waiting period for each nuclear plant.

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, 2018 under the NEIL policies would be $56 million and $85 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, Alabama Power's, and Georgia Power'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.

Other Matters

Mississippi Power

In 2013, Mississippi Power submitted a lost revenue claim under the Deep Horizon Economic and Property Damages Settlement Agreement associated with the oil spill that occurred in the Gulf of Mexico in 2010. On May 14, 2018, Mississippi Power's claim was settled. The settlement proceeds of $18 million, net of expenses and income tax, are included in Mississippi Power's earnings for 2018. As of December 31, 2018, Mississippi Power had received half of the settlement proceeds.

Southern Company Gas

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, 2018, the facility's property, plant, and equipment had a net book value of $109 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, 2018. 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 or Southern Company Gas' financial statements.

4. REVENUE FROM CONTRACTS WITH CUSTOMERS

The registrants generate revenues from a variety of sources, some of which are excluded from the scope of ASC 606, such as leases, derivatives, and certain cost recovery mechanisms. See Note 1 under "Recently Adopted Accounting Standards – Revenue" for additional information on the adoption of ASC 606 for revenue from contracts with customers and under "Revenues" for additional information on the revenue policies of the registrants.

The following tables disaggregate revenue sources for the year ended December 31, 2018:

		2018
		(in millions)
Southern Company		
Operating revenues		
Retail electric revenues[a]		
Residential	$	6,608
Commercial		5,266
Industrial		3,224
Other		124
Natural gas distribution revenues		3,175
Alternative revenue programs[b]		(20)
Total retail electric and gas distribution revenues	$	18,377
Wholesale energy revenues[c][d]		1,896
Wholesale capacity revenues[d]		620
Other natural gas revenues[e]		699
Other revenues[f]		1,903
Total operating revenues	$	23,495

(a) Retail electric revenues include $75 million of leases and a net increase of $60 million from certain cost recovery mechanisms that are not accounted for as revenue under ASC 606. See Note 2 for additional information on cost recovery mechanisms.

(b) See Note 1 under "Revenues" for additional information on alternative revenue programs at the natural gas distribution utilities. Alternative revenue program revenues are presented net of any previously recognized program amounts billed to customers during the same accounting period.

(c) Wholesale energy revenues include $299 million of revenues accounted for as derivatives, primarily related to short-term physical energy sales in the wholesale electricity market. See Note 1 under "Revenues – Southern Power" and Note 14 for additional information on energy-related derivative contracts.

(d) Wholesale energy and wholesale capacity revenues include $384 million and $121 million, respectively, of PPA contracts accounted for as leases.

(e) Other natural gas revenues related to Southern Company Gas' energy and risk management activities are presented net of the related costs of those activities and include gross third-party revenues of $7.0 billion of which $3.9 billion relates to contracts that are accounted for as derivatives. See Note 16 under "Southern Company Gas" for additional information on the components of wholesale gas services operating revenues.

(f) Other revenues include $322 million of revenues not accounted for under ASC 606.

COMBINED NOTES TO FINANCIAL STATEMENTS (continued)
Southern Company and Subsidiary Companies 2018 Annual Report

	2018		
	Alabama Power	Georgia Power	Mississippi Power
		(in millions)	
Operating revenues			
Retail revenues[(a)(b)]			
Residential	$ 2,335	$ 3,301	$ 273
Commercial	1,578	3,023	286
Industrial	1,428	1,344	321
Other	26	84	9
Total retail electric revenues	$ 5,367	$ 7,752	$ 889
Wholesale energy revenues[(c)]	297	133	348
Wholesale capacity revenues	101	54	6
Other revenues[(b)(d)]	267	481	22
Total operating revenues	$ 6,032	$ 8,420	$ 1,265

(a) Retail revenues at Alabama Power, Georgia Power, and Mississippi Power include a net increase or (net reduction) of $152 million, $(19) million, and $(13) million, respectively, related to certain cost recovery mechanisms that are not accounted for as revenue under ASC 606. See Note 2 for additional information on cost recovery mechanisms.

(b) Retail revenues and other revenues at Georgia Power include $74 million and $135 million, respectively, of revenues accounted for as leases.

(c) Wholesale energy revenues at Alabama Power, Georgia Power, and Mississippi Power include $20 million, $29 million, and $4 million, respectively, accounted for as derivatives primarily related to short-term physical energy sales in the wholesale electricity market. See Note 14 for additional information on energy-related derivative contracts.

(d) Other revenues at Alabama Power and Georgia Power include $57 million and $109 million, respectively, of revenues not accounted for under ASC 606.

	2018
	(in millions)
Southern Power	
PPA capacity revenues[(a)]	$ 580
PPA energy revenues[(a)]	1,140
Non-PPA revenues[(b)]	472
Other revenues	13
Total operating revenues	$ 2,205

(a) PPA capacity revenues and PPA energy revenues include $186 million and $413 million, respectively, related to PPAs accounted for as leases. See Note 1 under "Revenues – Southern Power" for additional information on capacity revenues accounted for as leases.

(b) Non-PPA revenues include $242 million of revenues from short-term sales related to physical energy sales in the wholesale electricity market accounted for as derivatives. See Note 1 under "Revenues – Southern Power" and Note 14 for additional information on energy-related derivative contracts.

	2018
	(in millions)
Southern Company Gas	
Operating revenues	
Natural gas distribution revenues	
Residential	$ 1,525
Commercial	436
Transportation	944
Industrial	40
Other	230
Alternative revenue programs[a]	(20)
Total natural gas distribution revenues	$ 3,155
Gas pipeline investments	32
Wholesale gas services[b]	101
Gas marketing services[c]	568
Other revenues	53
Total operating revenues	$ 3,909

(a) See Note 1 under "Revenues – Southern Company Gas" for additional information on alternative revenue programs at the natural gas distribution utilities. Alternative revenue program revenues are presented net of any previously recognized program amounts billed to customers during the same accounting period.

(b) Wholesale gas services revenues are presented net of the related costs associated with its energy trading and risk management activities. Operating revenues, as presented, include gross third-party revenues of $7.0 billion of which $3.9 billion relates to contracts that are accounted for as derivatives. See Note 16 under "Southern Company Gas" for additional information on the components of wholesale gas services operating revenues and Note 14 for additional information on energy-related derivative contracts.

(c) Gas marketing services includes $3 million of revenues not accounted for under ASC 606.

Contract Balances

The following table reflects the closing balances of receivables, contract assets, and contract liabilities related to revenues from contracts with customers at December 31, 2018:

	Receivables	Contract Assets	Contract Liabilities
		(in millions)	
Southern Company	$ 2,630	$ 102	$ 32
Alabama Power	520	—	12
Georgia Power	721	58	7
Mississippi Power	100	—	—
Southern Power	118	—	11
Southern Company Gas	952	—	2

As of December 31, 2018, Alabama Power had contract liabilities for outstanding performance obligations primarily related to extended service agreements. Georgia Power had contract assets primarily related to fixed retail customer bill programs where the payment is contingent upon Georgia Power's continued performance and the customer's continued participation in the program over the one-year contract term and to unregulated service agreements where payment is contingent upon project completion. Georgia Power also had contract liabilities for outstanding performance obligations primarily related to unregulated service agreements. Southern Power's contract liabilities relate to collections recognized in advance of revenue for certain levelized PPAs with Georgia Power. Southern Company's unregulated distributed generation business had $39 million and $11 million of contract assets and contract liabilities, respectively, at December 31, 2018 remaining for outstanding performance obligations.

Remaining Performance Obligations

The traditional electric operating companies and Southern Power have long-term contracts with customers in which revenues are recognized as performance obligations are satisfied over the contract term. These contracts primarily relate to PPAs whereby the traditional electric operating companies and Southern Power provide electricity and generation capacity to a customer. The revenue recognized for the delivery of electricity is variable; however, certain PPAs include a fixed payment for fixed generation capacity over the term of the contract. Southern Company's unregulated distributed generation business also has partially satisfied performance obligations related to certain fixed price contracts. Revenues from contracts with customers related to these performance obligations remaining at December 31, 2018 are expected to be recognized as follows:

	2019	2020	2021	2022	2023	2024 and Thereafter
			(in millions)			
Southern Company(*)	$ 487	$ 341	$ 315	$ 315	$ 306	$ 2,103
Alabama Power	23	22	26	23	22	140
Georgia Power	41	38	40	30	31	82
Mississippi Power	3	3	1	—	—	—
Southern Power	323	295	270	281	275	2,028

(*) Excludes amounts related to held for sale assets. See Note 15 under "Southern Company's Sale of Gulf Power" for additional information.

5. PROPERTY, PLANT, AND EQUIPMENT

Property, plant, and equipment is stated at original cost or fair value at acquisition, as appropriate, less any regulatory disallowances and impairments. Original cost may include: 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/or cost of equity funds used during construction.

The registrants' property, plant, and equipment in service consisted of the following at December 31, 2018 and 2017:

At December 31, 2018:	Southern Company	Alabama Power	Georgia Power	Mississippi Power	Southern Power	Southern Company Gas
			(in millions)			
Electric utilities:						
Generation	$ 52,324	$ 16,533	$ 19,145	$ 2,849	$ 13,246	$ —
Transmission	11,344	4,380	6,156	769	—	—
Distribution	18,746	7,389	10,389	968	—	—
General/other	4,446	2,100	1,985	314	25	—
Electric utilities' plant in service	86,860	30,402	37,675	4,900	13,271	—
Southern Company Gas:						
Natural gas distribution utilities transportation and distribution	12,409	—	—	—	—	12,409
Storage facilities	1,640	—	—	—	—	1,640
Other	1,128	—	—	—	—	1,128
Southern Company Gas plant in service	15,177	—	—	—	—	15,177
Other plant in service	1,669	—	—	—	—	—
Total plant in service	$ 103,706	$ 30,402	$ 37,675	$ 4,900	$ 13,271	$ 15,177

At December 31, 2017:	Southern Company	Alabama Power	Georgia Power	Mississippi Power	Southern Power	Southern Company Gas
			(in millions)			
Electric utilities:						
Generation	$ 51,279	$ 14,213	$ 17,038	$ 2,801	$ 13,737	$ —
Transmission	11,562	4,119	5,947	737	—	—
Distribution	19,239	7,034	9,978	946	—	—
General/other	4,402	1,960	1,898	289	18	—
Electric utilities' plant in service	86,482	27,326	34,861	4,773	13,755	—
Southern Company Gas:						
Natural gas distribution utilities transportation and distribution	13,079	—	—	—	—	13,079
Storage facilities	1,599	—	—	—	—	1,599
Other	1,155	—	—	—	—	1,155
Southern Company Gas plant in service	15,833	—	—	—	—	15,833
Other plant in service	1,227	—	—	—	—	—
Total plant in service	$ 103,542	$ 27,326	$ 34,861	$ 4,773	$ 13,755	$ 15,833

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 and certain maintenance costs including those described below.

In accordance with orders from their respective state PSCs, Alabama Power and Georgia Power defer nuclear outage operations and maintenance expenses to a regulatory asset when the charges are incurred. Alabama Power amortizes the costs over a subsequent 18-month period with Plant Farley's fall outage cost amortization beginning in January of the following year and spring outage cost amortization beginning in July of the same year. Georgia Power amortizes its costs over each unit's operating cycle, or 18 months for Plant Vogtle Units 1 and 2 and 24 months for Plant Hatch Units 1 and 2.

A portion of Mississippi Power's railway track maintenance costs is charged to fuel stock and recovered through Mississippi Power's fuel clause.

The portion of Southern Company Gas' non-working gas used to maintain the structural integrity of 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.

Capital Leases

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

	Southern Company	Georgia Power
	(in millions)	
At December 31, 2018:		
Office buildings	**$ 216**	**$ 61**
PPAs(*)	**—**	**144**
Computer-related equipment	**43**	**—**
Gas pipeline	**7**	**—**
Less: Accumulated amortization	**(75)**	**(84)**
Balance, net of amortization	**$ 191**	**$ 121**
At December 31, 2017:		
Office buildings	$ 216	$ 61
PPAs(*)	—	144
Computer-related equipment	51	—
Gas pipeline	6	—
Less: Accumulated amortization	(72)	(68)
Balance, net of amortization	$ 201	$ 137

(*) Represents Georgia Power's affiliate PPAs with Southern Power. See Note 1 under "Affiliate Transactions" and Note 9 under "Fuel and Power Purchase Agreements – Affiliate" for additional information.

See Note 8 under "Long-term Debt – Capital Leases" for additional information.

Depreciation and Amortization

The traditional electric operating companies' and Southern Company Gas' depreciation of the original cost of utility plant in service is provided primarily by using composite straight-line rates. The approximate rates for 2018, 2017, and 2016 are as follows:

	2018	2017	2016
		(percent)	
Alabama Power	**3.0%**	2.9%	3.0%
Georgia Power	**2.6%**	2.7%	2.8%
Mississippi Power(*)	**4.1%**	3.7%	4.2%
Southern Company Gas	**2.9%**	2.9%	2.8%

(*) Mississippi Power's decrease in 2017 is primarily the result of recording a loss on its lignite mine in June 2017.

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. In 2016, Alabama Power 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.

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.

Southern Company's 2017 depreciation includes $34 million of reductions in depreciation recognized by Gulf Power under the terms of its 2013 rate case settlement agreement with the Florida PSC.

When property, plant, and equipment 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.

At December 31, 2018 and 2017, accumulated depreciation for utility plant in service totaled $30.3 billion and $30.8 billion, respectively, for Southern Company and $4.3 billion and $4.5 billion, respectively, for Southern Company Gas.

Depreciation of the original cost of other plant in service is provided primarily on a straight-line basis over estimated useful lives, which for Southern Company range up to 65 years and for Southern Company Gas range from five to 15 years for transportation equipment, 40 to 60 years for storage facilities, and up to 65 years for other assets. At December 31, 2018 and 2017, accumulated depreciation for other plant in service totaled $766 million and $673 million, respectively, for Southern Company and $129 million and $75 million, respectively, for Southern Company Gas.

Southern Power

Southern Power applies component depreciation, where depreciation is computed principally by the straight-line method over the estimated useful life of the asset. 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. The primary assets in Southern Power's property, plant, and equipment are generating facilities, which generally have estimated useful lives as follows:

Southern Power 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

Southern Power 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 Southern Power's net income in the near term.

When Southern Power's 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 statements of income.

Joint Ownership Agreements

At December 31, 2018, the registrants' percentage ownership and investment (exclusive of nuclear fuel) in jointly-owned facilities in commercial operation were as follows:

Facility (Type)	Percent Ownership	Plant in Service	Accumulated Depreciation	CWIP
			(in millions)	
Alabama Power				
Greene County (natural gas) Units 1 and 2	60.0% [a]	$ 274	$ 71	$ 1
Plant Miller (coal) Units 1 and 2	91.8 [b]	2,056	619	138
Georgia Power				
Plant Hatch (nuclear)	50.1% [c]	$ 1,569	$ 615	$ 54
Plant Vogtle (nuclear) Units 1 and 2	45.7 [c]	3,804	2,150	84
Plant Scherer (coal) Units 1 and 2	8.4 [c]	266	96	14
Plant Scherer (coal) Unit 3	75.0 [c]	1,238	493	66
Plant Wansley (coal)	53.5 [c]	1,179	362	160
Rocky Mountain (pumped storage)	25.4 [d]	184	135	—
Mississippi Power				
Greene County (natural gas) Units 1 and 2	40.0% [a]	$ 180	$ 93	$ 1
Plant Daniel (coal) Units 1 and 2	50.0 [e]	723	201	7
Southern Company Gas				
Dalton Pipeline (natural gas pipeline)	50.0% [f]	$ 270	$ 6	$ —

(a) Jointly owned by Alabama Power and Mississippi Power and operated and maintained by Alabama Power.

(b) Jointly owned with PowerSouth and operated and maintained by Alabama Power.

(c) Georgia Power owns undivided interests in Plants Hatch, Vogtle Units 1 and 2, Scherer, and Wansley in varying amounts jointly with one or more of the following entities: OPC, MEAG Power, Dalton, Florida Power & Light Company, JEA, and Gulf Power. Georgia Power 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.

(d) Jointly owned with OPC, which is the operator of the plant.

(e) Jointly owned by Gulf Power and Mississippi Power. In accordance with the operating agreement, Mississippi Power acts as Gulf Power's agent with respect to the operation and maintenance of these units.

(f) Jointly owned with The Williams Companies, Inc. The Dalton Pipeline is a 115-mile natural gas pipeline that serves as an extension of the Transco natural gas pipeline system into northwest Georgia. Southern Company Gas also entered into an agreement to lease its 50% undivided ownership in the Dalton Pipeline that became effective when it was placed in service in August 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.

Georgia Power also owns 45.7% of Plant Vogtle Units 3 and 4, which are currently under construction and had a CWIP balance of $4.5 billion at December 31, 2018. See Note 2 under "Georgia Power – Nuclear Construction" for additional information.

On December 4, 2018, Southern Power completed the sale of its 65% ownership interest in Plant Stanton Unit A, which Southern Power previously jointly-owned with OUC, the FMPA, and the KUA, to NextEra Energy. See Note 15 under "Southern Power – Sales of Natural Gas Plants" for additional information.

In conjunction with Southern Company's sale of Gulf Power, Mississippi Power and Gulf Power have committed to seek a restructuring of their 50% undivided ownership interests in Plant Daniel such that each of them would, after the restructuring, own 100% of a generating unit. On January 15, 2019, Gulf Power provided notice to Mississippi Power that Gulf Power will retire its share of the generating capacity of Plant Daniel on January 15, 2024. Mississippi Power has the option to purchase Gulf Power's ownership interest for $1 on January 15, 2024, provided that Mississippi Power exercises the option no later than 120 days prior to that date. Mississippi Power is assessing the potential operational and economic effects of Gulf Power's notice. The ultimate outcome of these matters remains subject to completion of Mississippi Power's evaluations and applicable regulatory

approvals, including the FERC and the Mississippi PSC, and cannot now be determined. See Note 15 under "Southern Company's Sale of Gulf Power" for information regarding the sale of Gulf Power.

The registrants' proportionate share of their jointly-owned facility operating expenses is included in the corresponding operating expenses in the statements of income and each registrant is responsible for providing its own financing.

Assets Subject to Lien

On October 2, 2018, the Mississippi PSC approved executed agreements between Mississippi Power and its largest retail customer, Chevron Products Company (Chevron), for Mississippi Power 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 $101 million at December 31, 2018, 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 Mississippi Power's credit rating to below investment grade by two of the three rating agencies.

Under the terms of the PPA and the expansion PPA for Southern Power's Plant Mankato, which was acquired in 2016, approximately $563 million of assets, primarily related to property, plant, and equipment, are subject to lien at December 31, 2018. See Note 15 under "Southern Power – Sales of Natural Gas Plants" for additional information regarding the proposed sale of Plant Mankato.

See Note 3 under "General Litigation Matters – Southern Power" for information regarding liens on Southern Power's Roserock facility.

See Note 8 under "Secured Debt" for information regarding debt secured by certain assets of Georgia Power, Mississippi Power, and Southern Company Gas.

6. ASSET RETIREMENT OBLIGATIONS

AROs are computed as the present value of the estimated costs for an asset's future retirement and are recorded in the period in which the liability is incurred. The estimated 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 regulatory liabilities and amounts to be recovered are reflected in the balance sheets as regulatory assets.

The ARO liabilities for the traditional electric operating companies primarily relate to facilities that are subject to the CCR Rule, principally ash ponds. In addition, Alabama Power and Georgia Power have retirement obligations related to the decommissioning of nuclear facilities (Alabama Power's Plant Farley and Georgia Power's ownership interests in Plant Hatch and Plant Vogtle Units 1 and 2). See "Nuclear Decommissioning" herein for additional information. The traditional electric operating companies also have AROs related to various landfill sites, asbestos removal, and underground storage tanks, as well as, for Alabama Power, disposal of polychlorinated biphenyls in certain transformers and sulfur hexafluoride gas in certain substation breakers, for Georgia Power, gypsum cells, and for Mississippi Power, mine reclamation and water wells. The ARO liability for Southern Power primarily relates to Southern Power's solar and wind facilities, which are located on long-term land leases requiring the restoration of land at the end of the lease.

The traditional electric operating companies and Southern Company Gas also have identified other retirement obligations, such as obligations related to certain electric transmission and distribution facilities, certain asbestos containing material within long-term assets not subject to ongoing repair and maintenance activities, certain wireless communication towers, the disposal of polychlorinated biphenyls in certain transformers, leasehold improvements, equipment on customer property, and property associated with the Southern Company system's rail lines and natural gas pipelines. However, liabilities for the removal of these assets have not been recorded because the settlement timing for certain 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 retirement obligations will be recognized when sufficient information becomes available to support a reasonable estimation of the ARO.

Southern Company and the traditional electric operating companies will continue to recognize in their respective 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 in the balance sheets as ordered by the various state PSCs.

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

	Southern Company	Alabama Power	Georgia Power	Mississippi Power	Southern Power
			(in millions)		
Balance at December 31, 2016	$ 4,514	$ 1,533	$ 2,532	$ 179	$ 64
Liabilities incurred	16	—	4	—	6
Liabilities settled	(177)	(26)	(120)	(23)	—
Accretion	179	77	89	5	4
Cash flow revisions	292	125	133	13	4
Balance at December 31, 2017	**$ 4,824**	**$ 1,709**	**$ 2,638**	**$ 174**	**$ 78**
Liabilities incurred	**29**	**—**	**27**	**—**	**2**
Liabilities settled	**(244)**	**(55)**	**(116)**	**(35)**	**—**
Accretion	**217**	**106**	**94**	**5**	**4**
Cash flow revisions	**4,737**	**1,450**	**3,186**	**16**	**—**
Reclassification to held for sale	**(169)**	**—**	**—**	**—**	**—**
Balance at December 31, 2018	**$ 9,394**	**$ 3,210**	**$ 5,829**	**$ 160**	**$ 84**

In June 2018, Alabama Power recorded an increase of approximately $1.2 billion to its AROs related to the CCR Rule. Mississippi Power also recorded an increase of approximately $11 million to its AROs related to an ash pond at Plant Greene County, which is jointly-owned with Alabama Power. The revised cost estimates were based on information from feasibility studies performed on ash ponds in use at plants operated by Alabama Power, including Plant Greene County. During the second quarter 2018, Alabama Power's management completed its analysis of these studies which indicated that additional closure costs, primarily related to increases in estimated ash volume, water management requirements, and design revisions, will be required to close these ash ponds under the planned closure-in-place methodology. As the level of work becomes more defined in the next 12 months, it is likely that these cost estimates will change and the change could be material.

In December 2018, Georgia Power recorded an increase of approximately $3.1 billion to its AROs related to the CCR Rule and the related state rule. During the second half of 2018, Georgia Power completed a strategic assessment related to its plans to close the ash ponds at all of its generating plants in compliance with the CCR Rule and the related state rule. This assessment included engineering and constructability studies related to design assumptions for ash pond closures and advanced engineering methods. The results indicated that additional closure costs will be required to close these ash ponds, primarily due to changes in closure strategies, the estimated amount of ash to be excavated, and additional water management requirements necessary to support closure strategies. These factors also impact the estimated timing of future cash outlays.

In June 2018, Alabama Power completed an updated decommissioning cost site study for Plant Farley. The estimated cost of decommissioning based on the study resulted in an increase in Alabama Power's ARO liability of approximately $300 million. In December 2018, Georgia Power completed updated decommissioning cost site studies for Plant Hatch and Plant Vogtle Units 1 and 2. The estimated cost of decommissioning based on the studies resulted in an increase in Georgia Power's ARO liability of approximately $130 million. See "Nuclear Decommissioning" below for additional information.

The 2018 reclassification of a portion of the ARO liability to liabilities held for sale by Southern Company represents the AROs related to Gulf Power. See Note 15 under "Southern Company's Sale of Gulf Power" and "Assets Held for Sale" for additional information.

In 2017, Alabama Power's and Georgia Power's cash flow revisions were primarily related to changes in closure strategy for ash ponds and landfills. Georgia Power's cash flow revisions in 2017 also related to changes in closure strategy for gypsum cells. Mississippi Power's cash flow revisions in 2017 primarily related to a revision in the closure date of its lignite mine. The liabilities settled in 2017 for Alabama Power, Georgia Power, and Mississippi Power were primarily related to ash pond closure activity.

The cost estimates for AROs related to the CCR Rule are based on information at December 31, 2018 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. The traditional electric operating companies expect to continue to periodically update their ARO cost estimates, which could increase further, as additional information becomes available. Absent continued recovery of ARO costs through regulated rates, Southern Company's and the traditional electric operating companies' results of operations, cash flows, and financial condition could be materially impacted. The ultimate outcome of this matter cannot be determined at this time.

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 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.

Alabama Power and Georgia Power record the investment securities held in the Funds at fair value, as disclosed in Note 13, 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, Georgia Power's 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. At December 31, 2018 and 2017, approximately $27 million and $76 million, respectively, of the fair market value of Georgia Power's 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 $28 million and $77 million at December 31, 2018 and 2017, 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.

Investment securities in the Funds for December 31, 2018 and 2017 were as follows:

	Southern Company	Alabama Power	Georgia Power
		(in millions)	
At December 31, 2018:			
Equity securities	$ 919	$ 594	$ 325
Debt securities	726	201	525
Other securities	74	51	23
Total investment securities in the Funds	$ 1,719	$ 846	$ 873
At December 31, 2017:			
Equity securities	$ 1,059	$ 644	$ 415
Debt securities	725	223	502
Other securities	47	35	12
Total investment securities in the Funds	$ 1,831	$ 902	$ 929

These amounts exclude receivables related to investment income and pending investment sales and payables related to pending investment purchases. For Southern Company and Georgia Power, these amounts include Georgia Power's investment securities pledged to creditors and collateral received and excludes payables related to Georgia Power's securities lending program.

The fair value increases (decreases) of the Funds, including reinvested interest and dividends and excluding the Funds' expenses, for 2018, 2017, and 2016 are shown in the table below. The fair value increases (decreases) included unrealized gains (losses) on securities held in the Funds at each of December 31, 2018, 2017, and 2016, which are also shown in the table below.

	Southern Company	Alabama Power	Georgia Power
		(in millions)	
Fair value increases (decreases)			
2018	$ (67)	$ (38)	$ (29)
2017	233	125	108
2016	114	76	38
Unrealized gains (losses)			
At December 31, 2018	$ (183)	$ (96)	$ (87)
At December 31, 2017	181	98	83
At December 31, 2016	48	34	14

The investment securities held in 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 $17 million and $18 million at December 31, 2018 and 2017, 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, 2018 and 2017, the accumulated provisions for the external decommissioning trust funds were as follows:

	2018	2017
	(in millions)	
Alabama Power		
Plant Farley	**$ 846**	$ 902
Georgia Power		
Plant Hatch	**$ 547**	$ 583
Plant Vogtle Units 1 and 2	**326**	346
Total	**$ 873**	$ 929

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 at December 31, 2018 based on the most current studies, which were each performed in 2018, were as follows:

	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	$ 1,234	$ 734	$ 601
Spent fuel management	387	172	162
Non-radiated structures	99	56	79
Total site study costs	$ 1,720	$ 962	$ 842

(*) Based on Georgia Power's ownership interests.

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. Significant assumptions used to determine these costs for ratemaking were an estimated inflation rate of 4.5% and 2.4% for Alabama Power and Georgia Power, respectively, and an estimated 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.

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 the Georgia Power 2019 Base Rate Case.

7. CONSOLIDATED ENTITIES AND EQUITY METHOD INVESTMENTS

The registrants may hold ownership interests in a number of business ventures with varying ownership structures. Partnership interests and other variable interests are evaluated to determine if each entity is a VIE. If a venture is a VIE for which a registrant is the primary beneficiary, the assets, liabilities, and results of operations of the entity are consolidated. The registrants reassess the conclusion as to whether an entity is a VIE upon certain occurrences, which are deemed reconsideration events.

For entities that are not determined to be VIEs, the registrants evaluate whether they have control or significant influence over the investee to determine the appropriate consolidation and presentation. Generally, entities under the control of a registrant are consolidated, and entities over which a registrant can exert significant influence, but which a registrant does not control, are accounted for under the equity method of accounting. However, the registrants may also invest 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 in the balance sheets and, for Southern Company and Southern Company Gas, the equity income is recorded within earnings from equity method investments in the statements of income. See "SEGCO" and "Southern Company Gas" herein for additional information.

SEGCO

Alabama Power 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. Alabama Power and Georgia Power account for SEGCO using the equity method; Southern Company consolidates SEGCO. 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 Alabama Power and Georgia Power. Alabama Power and Georgia Power make payments sufficient to provide for the operating expenses, taxes, interest expense, and a ROE. The share of purchased power included in purchased power, affiliates in the statements of income totaled $102 million in 2018, $76 million in 2017, and $55 million in 2016 for Alabama Power and $105 million in 2018, $78 million in 2017, and $57 million in 2016 for Georgia Power.

SEGCO paid $18 million of dividends in 2018 and $24 million in each of 2017 and 2016, of which one-half of each was paid to each of Alabama Power and Georgia Power. In addition, Alabama Power and Georgia Power each recognize 50% of SEGCO's net income.

Alabama Power, 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. Alabama Power owns 14% of the pipeline with the remaining 86% owned by SEGCO.

See Note 9 under "Guarantees" for additional information regarding guarantees of Alabama Power and Georgia Power related to SEGCO.

Southern Power

Variable Interest Entities

Southern Power has certain wholly-owned subsidiaries that are determined to be VIEs. Southern Power 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.

SP Solar

On May 22, 2018, Southern Power sold a noncontrolling 33% limited partnership interest in SP Solar to Global Atlantic Financial Group Limited (Global Atlantic). See Note 15 under "Southern Power" for additional information. A wholly-owned subsidiary of Southern Power is the general partner and holds a 1% ownership interest in SP Solar and another wholly-owned subsidiary of Southern Power owns the remaining 66% ownership in SP Solar. SP Solar qualifies as a VIE since the arrangement is structured as a limited partnership and the 33% limited partner does not have substantive kick-out rights against the general partner. Southern Power previously consolidated SP Solar and will continue to do so as the primary beneficiary of the VIE since it controls the most significant activities of the partnership, including operating and maintaining its assets.

At December 31, 2018, SP Solar had total assets of $6.3 billion, total liabilities of $113 million, and noncontrolling interests of $1.2 billion. Cash distributions from SP Solar are allocated 67% to Southern Power and 33% to Global Atlantic in accordance with their partnership interest percentage. Under the terms of the limited partnership agreement, distributions without limited partner consent are limited to available cash and SP Solar is obligated to distribute all such available cash to its partners each quarter. Available cash includes all cash generated in the quarter subject to the maintenance of appropriate operating reserves.

Transfers and sales of the assets in the VIE are subject to limited partner consent and the liabilities do not have recourse to the general credit of Southern Power. Liabilities consist of customary working capital items and do not include any long-term debt.

SP Wind

On December 11, 2018, Southern Power sold a noncontrolling tax-equity interest in SP Wind to three financial investors. SP Wind owns eight operating wind farms. See Note 15 under "Southern Power" for additional information. Southern Power owns 100% of the class B membership interests and the three financial investors own 100% of the Class A membership interests. SP Wind qualifies as a VIE since the structure of the arrangement is similar to a limited partnership and the Class A members do not have substantive kick-out rights against Southern Power. Southern Power previously consolidated SP Wind and will continue to do so as the primary beneficiary of the VIE since it controls the most significant activities of the entity, including operating and maintaining its assets.

At December 31, 2018, SP Wind had total assets of $2.5 billion, total liabilities of $51 million, and noncontrolling interests of $47 million. Under the terms of the limited liability agreement, distributions without Class A member consent are limited to available cash and SP Wind is obligated to distribute all such available cash to its members each quarter. Available cash includes all cash

generated in the quarter subject to the maintenance of appropriate operating reserves. Cash distributions from SP Wind are generally allocated 60% to Southern Power and 40% to the three financial investors in accordance with the limited liability agreement.

Transfers and sales of the assets in the VIE are subject to Class A member consent and the liabilities do not have recourse to the general credit of Southern Power. Liabilities consist of customary working capital items and do not include any long-term debt.

Redeemable Noncontrolling Interests

In April 2017, Southern Power reclassified approximately $114 million from redeemable noncontrolling interests to non-redeemable noncontrolling interests due to the expiration of an option allowing SunPower Corporation to require Southern Power to purchase its redeemable noncontrolling interest at fair market value. In addition, in October 2017, Turner Renewable Energy, LLC redeemed at fair value its 10% interest of redeemable noncontrolling interest in certain of Southern Power's solar facilities. At December 31, 2018 and 2017, there were no outstanding redeemable noncontrolling interests.

The following table presents the changes in Southern Power's redeemable noncontrolling interests for the years ended December 31, 2017 and 2016:

	2017	2016
	(in millions)	
Beginning balance	$ 164	$ 43
Net income attributable to redeemable noncontrolling interests	2	4
Distributions to redeemable noncontrolling interests	(2)	(1)
Capital contributions from redeemable noncontrolling interests	2	118
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

The following table presents the attribution of net income to Southern Power and the noncontrolling interests for the years ended December 31, 2017 and 2016:

	2017	2016
	(in millions)	
Net income	$ 1,117	$ 374
Less: Net income attributable to noncontrolling interests	44	32
Less: Net income attributable to redeemable noncontrolling interests	2	4
Net income attributable to Southern Power	$ 1,071	$ 338

Southern Company Gas

SouthStar, previously a joint venture owned 85% by Southern Company Gas and 15% by Piedmont, was the only VIE for which Southern Company Gas was the primary beneficiary, prior to October 2016 when Southern Company Gas completed its purchase of Piedmont's remaining interest in SouthStar.

In 2015, Georgia Natural Gas Company (GNG), a 100%-owned, direct subsidiary of Southern Company Gas, 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.

Southern Company Gas' cash flows used for financing activities included SouthStar's distribution to Piedmont for its portion of SouthStar's annual earnings from the previous 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 period of January 1, 2016 through June 30, 2016, SouthStar distributed $19 million to Piedmont.

Equity Method Investments

The carrying amounts of Southern Company Gas' equity method investments at December 31, 2018 and 2017 and related income from those investments for the successor years ended December 31, 2018 and 2017, the successor period of July 1, 2016 through December 31, 2016, and the predecessor period of January 1, 2016 through June 30, 2016 were as follows:

Investment Balance	**December 31, 2018**	December 31, 2017
	(in millions)	
SNG	**$ 1,261**	$ 1,262
PennEast Pipeline	**71**	57
Atlantic Coast Pipeline	**83**	41
Other	**123**	117
Total	**$ 1,538**	$ 1,477

	Successor			Predecessor
Earnings from Equity Method Investments	**Year ended December 31, 2018**	Year ended December 31, 2017	July 1, 2016 through December 31, 2016	January 1, 2016 through June 30, 2016
		(in millions)		*(in millions)*
SNG	**$ 131**	$ 88	$ 56	$ —
PennEast Pipeline	**5**	6	—	—
Atlantic Coast Pipeline	**7**	6	1	—
Other	**5**	6	3	2
Total	**$ 148**	$ 106	$ 60	$ 2

SNG

In 2016, Southern Company Gas, through a wholly-owned, indirect subsidiary, acquired a 50% equity interest in SNG, which is accounted for as an equity method investment. See Note 15 under "Southern Company Gas – Investment in SNG" for additional information. Selected financial information of SNG at December 31, 2018 and 2017 and for the years ended December 31, 2018 and 2017 and for the period September 1, 2016 through December 31, 2016 is as follows:

	At December 31,	
Balance Sheet Information	**2018**	2017
	(in millions)	
Current assets	**$ 104**	$ 82
Property, plant, and equipment	**2,606**	2,439
Deferred charges and other assets	**121**	121
Total Assets	**$ 2,831**	$ 2,642
Current liabilities	**$ 103**	$ 110
Long-term debt	**1,103**	1,102
Other deferred charges and other liabilities	**212**	76
Total Liabilities	**$ 1,418**	$ 1,288
Total Stockholders' Equity	**$ 1,413**	$ 1,354
Total Liabilities and Stockholders' Equity	**$ 2,831**	$ 2,642

Income Statement Information	Year ended December 31, 2018	Year ended December 31, 2017	September 1, 2016 through December 31, 2016
		(in millions)	
Revenues	**$ 604**	$ 544	$ 230
Operating income	**310**	242	137
Net income	**261**	175	115

Other Investments

Pipelines

In 2014, Southern Company Gas entered into a partnership in which it holds a 20% ownership interest in the PennEast Pipeline, 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 Bcf per day, is under long-term contracts, mainly with public utilities and other market-serving entities, such as electric generation companies, in New Jersey, Pennsylvania, and New York.

Also in 2014, Southern Company Gas entered into a project in which it holds a 5% ownership interest in the Atlantic Coast Pipeline, 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.

See Note 2 under "FERC Matters – Southern Company Gas" for additional information on these pipeline projects.

Pivotal JAX LNG, LLC

Southern Company Gas owns a 50% interest in a LNG liquefaction and storage facility in Jacksonville, Florida, which was placed in service in October 2018. This facility is outfitted with a 2.0 million gallon storage tank with the capacity to produce in excess of 120,000 gallons of LNG per day.

8. FINANCING

Securities Due Within One Year

A summary of long-term securities due within one year at each of December 31, 2018 and 2017 is as follows:

	December 31, 2018					
	Southern Company	Alabama Power	Georgia Power	Mississippi Power	Southern Power	Southern Company Gas
	(in millions)					
Senior notes	$ 2,950	$ 200	$ 500	$ —	$ 600	$ 300
Revenue bonds[a]	173	—	108	40	—	—
First mortgage bonds	50	—	—	—	—	50
Capitalized leases	24	1	13	—	—	—
Other[b]	1	—	(4)	—	(1)	7
Total	$ 3,198	$ 201	$ 617	$ 40	$ 599	$ 357

(a) For Southern Company and Mississippi Power, 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.

(b) Represents unamortized debt related amounts, acquisition accounting fair value adjustments, and/or fair value hedges. See Note 14 for additional information regarding fair value hedges.

	December 31, 2017				
	Southern Company	Georgia Power	Mississippi Power	Southern Power	Southern Company Gas
	(in millions)				
Senior notes	$ 2,354	$ 750	$ —	$ 350	$ 155
Long-term bank term loans	1,420	100	900	420	—
Revenue bonds[a]	90	—	90	—	—
Capitalized leases	31	11	—	—	—
Other[b]	(3)	(4)	(1)	—	2
Total	$ 3,892	$ 857	$ 989	$ 770	$ 157

(a) For Southern Company and Mississippi Power, 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 for Southern Company and Mississippi Power, 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.

(b) Represents unamortized debt related amounts, acquisition accounting fair value adjustments, and fair value hedges. See Note 14 for additional information regarding fair value hedges.

Maturities of long-term debt for the next five years are as follows:

	Southern Company[a]	Alabama Power	Georgia Power[a]	Mississippi Power	Southern Power[b]	Southern Company Gas
	(in millions)					
2019	$ 3,156	$ 200	$ 621	$ —	$ 600	$ 350
2020	4,041	250	1,006	307	825	—
2021	3,186	310	375	270	300	330
2022	1,974	750	505	—	677	46
2023	2,388	300	153	—	290	400

(a) Amounts include principal amortization related to the FFB borrowings beginning in 2020; however, the final maturity date is February 20, 2044. See "Long-term Debt – DOE Loan Guarantee Borrowings" herein for additional information.

(b) Southern Power's 2022 maturity represents euro-denominated debt at the U.S. dollar denominated hedge settlement amount.

Long-term Debt

Senior Notes

Total senior notes (including amounts due within one year) outstanding at December 31, 2018 and 2017 were as follows:

	Southern Company[a]	Alabama Power	Georgia Power	Mississippi Power	Southern Power	Southern Company Gas[b]
			(in millions)			
December 31, 2018	**$ 32,725**	**$ 6,875**	**$ 5,600**	**$ 1,200**	**$ 5,050**	**$ 4,000**
December 31, 2017	35,148	6,375	7,100	755	5,459	4,157

(a) Includes $10.0 billion and $10.2 billion of senior notes at the Southern Company parent entity at December 31, 2018 and 2017, respectively.

(b) Represents senior notes issued by Southern Company Gas Capital, which are fully and unconditionally guaranteed by Southern Company Gas. See "Structural Considerations" herein for additional information.

See Note 14 for information regarding fair value hedges of existing senior notes.

Except as otherwise described herein, Southern Company and its subsidiaries used the proceeds of 2018 senior note issuances for long-term debt redemptions and maturities, to repay short-term indebtedness, and for general corporate purposes, including working capital. The subsidiaries also used the proceeds for their construction programs.

In August 2018, Southern Company issued $750 million aggregate principal amount of Series 2018A Floating Rate Senior Notes due February 14, 2020 bearing interest based on three-month LIBOR.

Subsequent to December 31, 2018, through cash tender offers, Southern Company repurchased and retired approximately $522 million of the $1.0 billion aggregate principal amount outstanding of its 1.85% Senior Notes due July 1, 2019 (1.85% Notes), approximately $180 million of the $350 million aggregate principal amount outstanding of its Series 2014B 2.15% Senior Notes due September 1, 2019 (Series 2014B Notes), and approximately $504 million of the $750 million aggregate principal amount outstanding of its Series 2018A Floating Rate Notes due February 14, 2020 (Series 2018A Notes), for an aggregate purchase price, excluding accrued and unpaid interest, of approximately $1.2 billion. In addition, subsequent to December 31, 2018, and following the completion of the cash tender offers, Southern Company completed the redemption of all of the Series 2018A Notes remaining outstanding and called for redemption all of the 1.85% Notes and Series 2014B Notes remaining outstanding.

In June 2018, Alabama Power issued $500 million aggregate principal amount of Series 2018A 4.30% Senior Notes due July 15, 2048.

In April 2018, Georgia Power redeemed all $250 million aggregate principal amount of its Series 2008B 5.40% Senior Notes due June 1, 2018.

In May 2018, through cash tender offers, Georgia Power repurchased and retired $89 million of the $250 million aggregate principal amount outstanding of its Series 2007A 5.65% Senior Notes due March 1, 2037, $326 million of the $500 million aggregate principal amount outstanding of its Series 2009A 5.95% Senior Notes due February 1, 2039, and $335 million of the $600 million aggregate principal amount outstanding of its Series 2010B 5.40% Senior Notes due June 1, 2040, for an aggregate purchase price, excluding accrued and unpaid interest, of $902 million.

In March 2018, Mississippi Power issued $300 million aggregate principal amount of Series 2018A Floating Rate Senior Notes due March 27, 2020 bearing interest based on three-month LIBOR and $300 million aggregate principal amount of Series 2018B 3.95% Senior Notes due March 30, 2028.

In October 2018, Mississippi Power completed the redemption of all $30 million aggregate principal amount outstanding of its Series G 5.40% Senior Notes due July 1, 2035 and all $125 million aggregate principal amount outstanding of its Series 2009A 5.55% Senior Notes due March 1, 2019.

Junior Subordinated Notes

Total junior subordinated notes outstanding for Southern Company and Georgia Power at December 31, 2018 and 2017 were as follows:

	Southern Company(*)	Georgia Power
	(in millions)	
December 31, 2018	**$ 3,570**	**$ 270**
December 31, 2017	3,570	270

(*) Includes $3.3 billion of junior subordinated notes at the Southern Company parent entity at both December 31, 2018 and 2017.

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 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. Total tax-exempt pollution control revenue bond obligations (including amounts due within one year) outstanding at December 31, 2018 and 2017 were as follows:

	Southern Company	Alabama Power	Georgia Power	Mississippi Power
		(in millions)		
December 31, 2018	**$ 2,585**	**$ 1,060**	**$ 1,460**	**$ 40**
December 31, 2017	3,297	1,060	1,821	83

In October 2018, Alabama Power purchased and held $120 million aggregate principal amount of The Industrial Development Board of the City of Mobile, Alabama Pollution Control Revenue Bonds (Alabama Power Company Plant Barry Project), Series 2008. Alabama Power reoffered these bonds to the public in November 2018.

During 2018, Georgia Power purchased and held the following pollution control revenue bonds, which may be reoffered to the public at a later date:

- approximately $105 million aggregate principal amount of Development Authority of Burke County (Georgia) Pollution Control Revenue Bonds (Georgia Power Company Plant Vogtle Project), First Series 2013
- $173 million aggregate principal amount of Development Authority of Bartow County (Georgia) Pollution Control Revenue Bonds (Georgia Power Company Plant Bowen Project), First Series 2009
- $55 million aggregate principal amount of Development Authority of Burke County (Georgia) Pollution Control Revenue Bonds (Georgia Power Company Plant Vogtle Project), Fifth Series 1994
- $65 million aggregate principal amount of Development Authority of Burke County (Georgia) Pollution Control Revenue Bonds (Georgia Power Company Plant Vogtle Project), Second Series 2008
- approximately $72 million aggregate principal amount of Development Authority of Bartow County (Georgia) Pollution Control Revenue Bonds (Georgia Power Company Plant Bowen Project), First Series 2013

In December 2018, the Development Authority of Burke County (Georgia) issued approximately $108 million aggregate principal amount of Pollution Control Revenue Bonds (Georgia Power Company Plant Vogtle Project), First Series 2018 due November 1, 2052 for the benefit of Georgia Power. The proceeds were used to redeem, in January 2019, approximately $13 million, $20 million, and $75 million aggregate principal amount of Development Authority of Burke County (Georgia) Pollution Control Revenue Bonds (Georgia Power Company Plant Vogtle Project), First Series 1992, Eighth Series 1994, and Second Series 1995, respectively.

In July 2018, Mississippi Power purchased and held approximately $43 million aggregate principal amount of Mississippi Business Finance Corporation Pollution Control Revenue Refunding Bonds, Series 2002. Mississippi Power may reoffer these bonds to the public at a later date.

Bank Term Loans

Total long-term bank term loans (including amounts due within one year) outstanding at December 31, 2018 and 2017 were as follows:

	Southern Company	Alabama Power	Georgia Power	Mississippi Power	Southern Power
			(in millions)		
December 31, 2018	**$ 145**	**$ 45**	**$ —**	**$ —**	**$ —**
December 31, 2017	1,465	45	100	900	420

See "Notes Payable" herein for additional information regarding bank term loans.

In January 2018, Georgia Power repaid its outstanding $100 million floating rate bank loan due October 26, 2018.

In March 2018, Mississippi Power repaid at maturity a $900 million unsecured term loan.

In May 2018, Southern Power repaid $420 million aggregate principal amount of long-term floating rate bank loans.

In November 2018, SEGCO, as borrower, and Alabama Power, as guarantor, entered into a $100 million long-term delayed draw floating rate bank term loan bearing interest based on three-month LIBOR, which SEGCO used to repay at maturity $100 million aggregate principal amount of Series 2013A Senior Notes. See Note 9 under "Guarantees" 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), 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.

In July 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.

In September 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 March 31, 2019, 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, 2018 and 2017, 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 (including any decision not to continue construction of Plant Vogtle Units 3 and 4) occur, the FFB's commitment to make further advances under the FFB Credit Facility will terminate and Georgia Power will be required to prepay the outstanding principal amount of all borrowings under the FFB Credit Facility over a period of five years (with level principal amortization). Among other things, these mandatory prepayment events include (i) the termination of the Vogtle Services Agreement or rejection of the Vogtle Services Agreement in bankruptcy if Georgia Power does not maintain access to intellectual property rights under the IP Licenses; (ii) a decision by Georgia Power not to continue construction of Plant Vogtle Units 3 and 4; (iii) cancellation of Plant Vogtle Units 3 and 4 by the Georgia PSC, or by Georgia Power if authorized by the Georgia PSC; and (iv) cost disallowances by the Georgia PSC that could have a material adverse effect on completion of Plant Vogtle Units 3 and 4 or Georgia Power's ability to repay the outstanding borrowings under the FFB Credit Facility. Under certain circumstances, insurance proceeds and any proceeds from an event of taking must be applied to immediately prepay outstanding borrowings under the FFB Credit Facility. In addition, if Georgia Power discontinues construction of Plant Vogtle Units 3 and 4, Georgia Power would be obligated to immediately repay a portion of the outstanding borrowings under the FFB Credit Facility to the extent such outstanding borrowings exceed 70% of Eligible Project Costs, net of the proceeds received by Georgia Power under the Guarantee Settlement Agreement. Georgia Power also may voluntarily prepay outstanding borrowings under the FFB Credit Facility. Under the FFB Credit Facility, any prepayment (whether mandatory or optional) will be made with a make-whole premium or discount, as applicable.

In connection with any cancellation of Plant Vogtle Units 3 and 4 that results in a mandatory prepayment event, the DOE may elect to continue construction of Plant Vogtle Units 3 and 4. In such an event, the DOE will have the right to assume Georgia Power's rights and obligations under the principal agreements relating to Plant Vogtle Units 3 and 4 and to acquire all or a portion of Georgia Power's ownership interest in Plant Vogtle Units 3 and 4.

Other Long-Term Debt

Alabama Power

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 at December 31, 2018 and 2017, 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, 2018 and 2017, 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.

Mississippi Power

At December 31, 2018 and 2017, Mississippi Power had $270 million aggregate principal amount outstanding of Mississippi Business Finance Corporation Taxable Revenue Bonds, 7.13% Series 1999A due October 20, 2021. Mississippi Power assumed the obligations in 2011 in connection with its election under its operating lease of Plant Daniel Units 3 and 4 to purchase the assets. The bonds were recorded at fair value at the date of assumption, or $346 million, reflecting a premium of $76 million. See "Secured Debt" herein for additional information.

At December 31, 2018 and 2017, Mississippi Power had $50 million of tax-exempt revenue bond obligations outstanding representing 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.

Southern Company Gas

At December 31, 2018 and 2017, Nicor Gas had $1.3 billion and $1.0 billion, respectively, of first mortgage bonds outstanding. These bonds have been issued with maturities ranging from 2019 to 2058. See "Secured Debt" herein for additional information.

Prior to its sale, in the second quarter 2018, Pivotal Utility Holdings caused $200 million aggregate principal amount of gas facility revenue bonds to be redeemed.

Nicor Gas issued $300 million aggregate principal amount of first mortgage bonds in a private placement, of which $100 million was issued in August 2018 and $200 million was issued in November 2018.

At both December 31, 2018 and 2017, Atlanta Gas Light had $159 million of medium-term notes 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. See Note 5 under "Capital Leases" for additional information.

Southern Company

At December 31, 2018 and 2017, SCS had capital lease obligations of approximately $178 million and $177 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 1.6% to 4.7%.

Georgia Power

At December 31, 2018 and 2017, Georgia Power had a capital lease obligation for its corporate headquarters building of $15 million and $22 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, 2018 and 2017, Georgia Power had capital lease obligations related to two affiliate PPAs with Southern Power of $128 million and $132 million, respectively. The annual interest rates range from 11% 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 Georgia Power's cost of debt. See Note 1 under "Affiliate Transactions" and Note 9 under "Fuel and Power Purchase Agreements – Affiliate" for additional information.

Secured Debt

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.

Outstanding secured debt at December 31, 2018 and 2017 for the applicable registrants was as follows:

	Georgia Power[a]	Mississippi Power[b]	Southern Company Gas[c]
		(in millions)	
December 31, 2018	**$ 2,767**	**$ 270**	**$ 1,325**
December 31, 2017	2,779	270	1,025

(a) Includes Georgia Power's FFB loans 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. These borrowings totaled $2.6 billion at both December 31, 2018 and 2017. See "Long-term Debt – DOE Loan Guarantee Borrowings" herein for additional information. Also includes capital lease obligations of $142 million and $154 million at December 31, 2018 and 2017, respectively. See "Long-term Debt – Capital Leases – Georgia Power" herein for additional information.

(b) 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 "Long-term Debt – Other Long-Term Debt" herein for additional information.

(c) Nicor Gas' first mortgage bonds are secured by substantially all of Nicor Gas' properties. See "Long-term Debt – Other Long-Term Debt – Southern Company Gas" herein for additional information.

At December 31, 2018 and 2017, Gulf Power had $41 million of secured debt related to a lien on its property at Plant Daniel in connection with the issuance of two series of its pollution control revenue bonds, which are included in liabilities held for sale on Southern Company's balance sheet at December 31, 2018. On January 1, 2019, Southern Company completed its sale of Gulf Power to NextEra Energy. See Note 15 under "Southern Company's Sale of Gulf Power" for additional information.

Each registrant's senior notes, junior subordinated notes, pollution control and other revenue bond obligations, bank term loans, credit facility borrowings, and notes payable are effectively subordinated to all secured debt of each respective registrant.

Bank Credit Arrangements

At December 31, 2018, committed credit arrangements with banks were as follows:

	Expires					Executable Term Loans		Expires Within One Year	
Company	2019	2020	2022	Total	Unused[d]	One Year	Two Years	Term Out	No Term Out
					(in millions)				
Southern Company[a]	$ —	$ —	$2,000	$ 2,000	$ 1,999	$ —	$ —	$ —	$ —
Alabama Power	33	500	800	1,333	1,333	—	—	—	33
Georgia Power	—	—	1,750	1,750	1,736	—	—	—	—
Mississippi Power	100	—	—	100	100	—	—	—	100
Southern Power[b]	—	—	750	750	727	—	—	—	—
Southern Company Gas[c]	—	—	1,900	1,900	1,895	—	—	—	—
Other	30	—	—	30	30	—	—	—	30
Southern Company Consolidated[e]	$ 163	$ 500	$7,200	$ 7,863	$ 7,820	$ —	$ —	$ —	$ 163

(a) Represents the Southern Company parent entity.

(b) Southern Power's subsidiaries are not parties to its bank credit arrangement.

(c) Southern Company Gas provides a parent guarantee of the obligations of its subsidiary Southern Company Gas Capital, which is the borrower of $1.4 billion ($1.395 billion unused) of this arrangement. Southern Company Gas' committed credit arrangement also includes $500 million (all unused) for which Nicor Gas is the borrower and which is restricted for working capital needs of Nicor Gas. Pursuant to this multi-year credit arrangement, the allocations between Southern Company Gas Capital and Nicor Gas may be adjusted. See "Structural Considerations" herein for additional information.

(d) Amounts used are for letters of credit.

(e) Excludes $280 million of committed credit arrangements of Gulf Power, which was sold on January 1, 2019. See Note 15 under "Southern Company's Sale of Gulf Power" for additional information.

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, 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, other hybrid securities. Additionally, for Southern Company and Southern Power, for purposes of these definitions, debt would exclude any project debt incurred by certain subsidiaries of Southern Power to the extent such debt is non-recourse to Southern Power and capitalization would exclude the capital stock or other equity attributable to such subsidiaries. At December 31, 2018, Southern Company, the traditional electric operating companies, Southern Power, Southern Company Gas, and Nicor Gas were each in compliance with their respective debt limit covenants.

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, Southern Company Gas, and Nicor Gas. The amount of variable rate revenue bonds of the traditional electric

operating companies outstanding requiring liquidity support at December 31, 2018 was approximately $1.6 billion (comprised of approximately $854 million at Alabama Power, $659 million at Georgia Power, $82 million at Gulf Power, and $40 million at Mississippi Power). In addition, at December 31, 2018, the traditional electric operating companies had approximately $403 million (comprised of approximately $345 million at Georgia Power and $58 million at Gulf Power) of revenue bonds outstanding that are required to be remarketed within the next 12 months. See Note 15 under "Southern Company's Sale of Gulf Power" for information regarding the sale of Gulf Power on January 1, 2019. Subsequent to December 31, 2018, Georgia Power redeemed approximately $108 million of obligations related to outstanding variable rate pollution control revenue bonds.

In addition to its credit arrangement described above, Southern Power also has a $120 million continuing letter of credit facility expiring in 2021 for standby letters of credit. At December 31, 2018, $103 million has been used for letters of credit, primarily as credit support for PPA requirements, and $17 million was unused. At December 31, 2017, the total amount available under this facility was $19 million. Southern Power's subsidiaries are not parties to this letter of credit facility. Also, at December 31, 2018 and 2017, Southern Power had $103 million and $113 million, respectively, of cash collateral posted related to PPA requirements, which is included in other deferred charges and assets in Southern Power's consolidated balance sheets.

Notes Payable

Southern Company, Alabama Power, Georgia Power, Southern Power, Southern Company Gas, Nicor Gas, and SEGCO make short-term borrowings primarily through commercial paper programs that have the liquidity support of the committed bank credit arrangements described above under "Bank Credit Arrangements." Southern Power's subsidiaries are not parties to its commercial paper program. Southern Company Gas maintains commercial paper programs at Southern Company Gas Capital and at Nicor Gas. 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 Southern Company Gas' other subsidiaries benefit from Southern Company Gas Capital's commercial paper program. See "Structural Considerations" herein for additional information.

In addition, 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.

Commercial paper and short-term bank term loans are included in notes payable in the balance sheets. Details of short-term borrowings were as follows:

	Notes Payable at December 31, 2018		Notes Payable at December 31, 2017	
	Amount Outstanding	Weighted Average Interest Rate	Amount Outstanding	Weighted Average Interest Rate
	(in millions)		*(in millions)*	
Southern Company				
Commercial paper	**$ 1,064**	**3.0%**	$ 1,832	1.8%
Short-term bank debt	**1,851**	**3.1%**	607	2.3%
Total	**$ 2,915**	**3.1%**	$ 2,439	1.9%
Alabama Power				
Short-term bank debt	**$ —**	**—%**	$ 3	3.7%
Georgia Power				
Commercial paper	**$ 294**	**3.1%**	$ —	—%
Short-term bank debt	**—**	**—%**	150	2.2%
Total	**$ 294**	**3.1%**	$ 150	2.2%
Mississippi Power				
Short-term bank debt	**$ —**	**—%**	$ 4	3.8%
Southern Power				
Commercial paper	**$ —**	**—%**	$ 105	2.0%
Short-term bank debt	**100**	**3.1%**	—	—%
Total	**$ 100**	**3.1%**	$ 105	2.0%
Southern Company Gas				
Commercial paper:				
Southern Company Gas Capital	**$ 403**	**3.1%**	$ 1,243	1.7%
Nicor Gas	**247**	**3.0%**	275	1.8%
Total	**$ 650**	**3.0%**	$ 1,518	1.8%

The outstanding bank term loans at December 31, 2018 have covenants that limit debt levels to a percentage of total capitalization. The percentage is 70% for Southern Company and 65% for Alabama Power and Southern Power, 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, for purposes of these definitions, debt excludes any project debt incurred by certain subsidiaries of Southern Power to the extent such debt is non-recourse to Southern Power and capitalization excludes the capital stock or other equity attributable to such subsidiary. At December 31, 2018, each of Southern Company, Alabama Power, and Southern Power was in compliance with its debt limits.

Except as otherwise described herein, Southern Company and its subsidiaries used the proceeds of bank loans for long-term debt redemptions and maturities, to repay short-term indebtedness, and for general corporate purposes, including working capital.

In March 2018, Southern Company entered into a $900 million short-term floating rate bank loan bearing interest based on one-month LIBOR, which was repaid in August 2018.

In April 2018, Southern Company borrowed $250 million pursuant to a short-term uncommitted bank credit arrangement, bearing interest at a rate agreed upon by Southern Company and the bank from time to time and payable on no less than 30 days' demand by the bank. Subsequent to December 31, 2018, Southern Company repaid this loan.

In June 2018, Southern Company repaid at maturity two $100 million short-term floating rate bank term loans.

In August 2018, Southern Company entered into a $1.5 billion short-term floating rate bank loan bearing interest based on one-month LIBOR, and repaid $250 million borrowed in August 2017 pursuant to a short-term uncommitted bank credit arrangement. Subsequent to December 31, 2018, Southern Company repaid this loan.

In January 2018, Georgia Power repaid its outstanding $150 million floating rate bank loan due May 31, 2018.

In March 2018, Mississippi Power entered into a $300 million short-term floating rate bank loan bearing interest based on one-month LIBOR, of which $200 million was repaid in the second quarter 2018 and $100 million was repaid in the third quarter 2018.

In May 2018, Southern Power entered into two short-term floating rate bank loans, each for an aggregate principal amount of $100 million, which bear interest based on one-month LIBOR. In November 2018, Southern Power repaid one of these short-term loans.

In January 2018, Southern Company Gas issued a floating rate promissory note to Southern Company in an aggregate principal amount of $100 million bearing interest based on one-month LIBOR. In March 2018, Southern Company Gas repaid this promissory note.

In April 2018, Pivotal Utility Holdings, as borrower, and Southern Company Gas, as guarantor, entered into a $181 million short-term delayed draw floating rate bank term loan bearing interest based on one-month LIBOR. In July 2018, Pivotal Utility Holdings repaid this short-term loan.

In May 2018, Southern Company Gas Capital borrowed $95 million pursuant to a short-term uncommitted bank credit arrangement, guaranteed by Southern Company Gas, bearing interest at a rate agreed upon by Southern Company Gas Capital and the bank from time to time and payable on no less than 30 days' demand by the bank. In July 2018, Southern Company Gas Capital repaid this loan.

Outstanding Classes of Capital Stock

Southern Company

Common Stock

Stock Issued

During 2018, Southern Company issued approximately 11.6 million shares of common stock primarily through employee equity compensation plans and received proceeds of approximately $442 million.

In addition, during the third and fourth quarters 2018, Southern Company issued a total of approximately 12.1 million and 2.5 million shares, respectively, 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 $540 million and $108 million, respectively, net of $5 million and $1 million in commissions, respectively.

Shares Reserved

At December 31, 2018, a total of 92 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 in Note 12), and an at-the-market program. Of the total 92 million shares reserved, there were 10 million shares of common stock remaining available for awards under the Omnibus Incentive Compensation Plan at December 31, 2018.

Diluted Earnings Per Share

For Southern Company, the only difference in computing basic and diluted earnings per share (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		
	2018	2017	2016
		(in millions)	
As reported shares	**1,020**	1,000	951
Effect of options and performance share award units	**5**	8	7
Diluted shares	**1,025**	1,008	958

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.

Redeemable Preferred Stock of Subsidiaries

Prior to 2017, each of the traditional electric operating companies had outstanding preferred and/or preference stock. During 2017, Alabama Power and Gulf Power redeemed all of their outstanding preference stock and Georgia Power redeemed all of its outstanding preferred and preference stock. During 2018, Mississippi Power redeemed all of its outstanding preferred stock. The remaining preferred stock of Alabama 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, this preferred stock is presented as "Redeemable Preferred Stock of Subsidiaries" on Southern Company's balance sheets and statements of capitalization in a manner consistent with temporary equity under applicable accounting standards.

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, 2015 and 2016:	$ 118
Issued[(a)]	250
Redeemed[(a)]	(38)
Issuance costs[(a)]	(6)
Balance at December 31, 2017:	324
Redeemed[(b)]	(33)
Balance at December 31, 2018:	**$ 291**

(a) See "Alabama Power" herein for additional information.

(b) See "Mississippi Power" herein for additional information.

Alabama Power

Alabama Power has preferred stock, Class A preferred stock, and common stock outstanding. Alabama Power also has authorized preference stock, none of which is outstanding. Alabama Power's preferred stock and Class A preferred stock, without preference between classes, rank senior to Alabama Power's common stock with respect to payment of dividends and voluntary and involuntary dissolution. The preferred stock and Class A preferred stock of Alabama Power contain a feature that allows the holders to elect a majority of Alabama Power'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, the preferred stock and Class A preferred stock is presented as "Redeemable Preferred Stock" on Alabama Power's balance sheets and statements of capitalization in a manner consistent with temporary equity under applicable accounting standards.

Alabama Power's preferred stock is subject to redemption at a price equal to the par value plus a premium. Alabama Power's Class A preferred stock is subject to redemption at a price equal to the stated capital. All series of Alabama Power's preferred stock currently are subject to redemption at the option of Alabama Power. 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 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, 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 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 Alabama Power's continuous construction program.

There were no changes for the year ended December 31, 2018 in redeemable preferred stock of Alabama Power.

Georgia Power

Georgia Power has preferred stock, Class A preferred stock, preference stock, and common stock authorized, but only common stock outstanding as of December 31, 2018 and 2017. In October 2017, Georgia Power 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.

Mississippi Power

Mississippi Power has preferred stock and common stock authorized, but only common stock outstanding as of December 31, 2018. Mississippi Power previously had preferred stock that contained a feature allowing the holders to elect a majority of Mississippi Power's board of directors if preferred dividends were not paid for four consecutive quarters. Because such a potential redemption-triggering event was not solely within the control of Mississippi Power, this preferred stock was presented as "Cumulative Redeemable Preferred Stock" on Mississippi Power's balance sheets and statements of capitalization in a manner consistent with temporary equity under applicable accounting standards.

On October 23, 2018, Mississippi Power completed the redemption of all 8,867 outstanding shares ($886,700 aggregate par value) of its 4.40% Series Preferred Stock, all 8,643 outstanding shares ($864,300 aggregate par value) of its 4.60% Series Preferred Stock, all 16,700 outstanding shares ($1.67 million aggregate par value) of its 4.72% Series Preferred Stock, and all 1,200,000 outstanding depositary shares ($30 million aggregate stated value), each representing a 1/4th interest in a share of its 5.25% Series Preferred Stock.

Dividend Restrictions

The income of Southern Company is derived primarily from equity in earnings of its subsidiaries. At December 31, 2018, consolidated retained earnings included $4.9 billion of undistributed retained earnings of the subsidiaries.

The traditional electric operating companies and Southern Power can only pay dividends to Southern Company out of retained earnings or paid-in-capital.

See Note 7 under "Southern Power" for information regarding the distribution requirements for certain Southern Power subsidiaries.

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 and is not permitted to make money pool loans to affiliates. At December 31, 2018, the amount of Southern Company Gas' subsidiary retained earnings restricted for dividend payment totaled $814 million.

Structural Considerations

Since Southern Company and Southern Company Gas are holding companies, the right of Southern Company and Southern Company Gas and, hence, the right of creditors of Southern Company or Southern Company Gas to participate in any distribution of the assets of any respective subsidiary of Southern Company or Southern Company Gas, whether upon liquidation, reorganization or otherwise, is subject to prior claims of creditors and preferred stockholders of such subsidiary.

Southern Company Gas' 100%-owned subsidiary, Southern Company Gas Capital, was established to provide for certain of Southern Company Gas' 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. Nicor Gas is not permitted by regulation to make loans to affiliates or utilize Southern Company Gas Capital for its financing needs.

Southern Power Company's senior notes, bank term loans, commercial paper, and bank credit arrangement are unsecured senior indebtedness, which rank equally with all other unsecured and unsubordinated debt of Southern Power Company. Southern Power's subsidiaries are not issuers, borrowers, or obligors, as applicable, under the senior notes, borrowings from financial institutions, commercial paper, or the bank credit arrangement. The senior notes, borrowings from financial institutions, commercial paper, and the bank credit arrangement are effectively subordinated to any future secured debt of Southern Power Company and any potential claims of creditors of Southern Power's subsidiaries.

9. COMMITMENTS

Fuel and Power Purchase Agreements

Non-Affiliate

To supply a portion of the fuel requirements of the Southern Company system's electric generating plants, the Southern Company system has entered into various long-term commitments not recognized on the balance sheets for the procurement and delivery of fossil fuel and, for Alabama Power and Georgia Power, nuclear fuel. Fuel expense in 2018, 2017, and 2016 for the Southern Company system is shown below, the majority of which was purchased under long-term commitments.

	Southern Company	Alabama Power	Georgia Power	Mississippi Power	Southern Power
			(in millions)		
2018	$ 4,637	$ 1,301	$ 1,698	$ 405	$ 699
2017	4,400	1,225	1,671	395	621
2016	4,361	1,297	1,807	343	456

Each registrant expects that a substantial amount of its future fuel needs will continue to be purchased under long-term commitments.

The traditional electric operating companies have entered into various non-affiliate long-term PPAs, some of which are accounted for as leases. For Alabama Power and Georgia Power, most long-term PPAs include capacity and energy components. Mississippi Power's long-term PPAs are associated with solar facilities and only include an energy component. For the traditional electric operating companies, the energy-related costs associated with PPAs are recoverable through fuel cost recovery provisions.

Total capacity expense under these non-affiliate PPAs accounted for as operating leases in 2018, 2017, and 2016 was as follows:

	Southern Company	Alabama Power	Georgia Power
		(in millions)	
2018	$ 231	$ 44	$ 113
2017	235	41	118
2016	232	42	113

In addition, Georgia Power's non-affiliate energy-only solar PPAs accounted for as leases contained contingent rent expense of $43 million, $44 million, and $18 million for 2018, 2017, and 2016, respectively. Mississippi Power's energy-only solar PPAs accounted for as operating leases contained contingent rent expense of $10 million, $5 million, and an immaterial amount for 2018, 2017, and 2016, respectively. Contingent rents are recognized as services are performed.

Estimated total obligations under non-affiliate PPAs accounted for as operating leases at December 31, 2018 were as follows:

	Southern Company	Alabama Power	Georgia Power
		(in millions)	
2019	$ 161	$ 41	$ 120
2020	164	42	122
2021	168	44	124
2022	171	46	125
2023	127	—	127
2024 and thereafter	642	—	642
Total	$ 1,433	$ 173	$ 1,260

In addition, Georgia Power 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 in Southern Company's statements of income and in purchased power, non-affiliates in Georgia Power's statements of income. Georgia Power's capacity payments related to this commitment totaled $8 million, $9 million, and $11 million in 2018, 2017, and 2016, respectively. At December 31, 2018, Georgia Power's estimated long-term obligations related to this commitment totaled $59 million, consisting of $6 million for 2019, $5 million for 2020, $5 million for 2021, $4 million for 2022, $3 million for 2023, and $36 million for 2024 and thereafter.

SCS may enter into various types of wholesale energy and natural gas contracts acting as an agent for the 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 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 Southern Power as a contracting party under these agreements.

Affiliate

Georgia Power has also entered into affiliate long-term PPAs with Southern Power, some of which Georgia Power accounts for as leases. Georgia Power's total capacity expense under these affiliate PPAs accounted for as leases was $93 million, $107 million, and $133 million in 2018, 2017, and 2016, respectively. In addition, Georgia Power's energy-only solar PPAs with Southern Power accounted for as leases contained contingent rent expense of $29 million, $29 million, and $21 million for 2018, 2017, and 2016, respectively.

Georgia Power's estimated total obligations under affiliate PPAs accounted for as leases at December 31, 2018 were as follows:

	Georgia Power	
	Affiliate Capital Lease PPAs	Affiliate Operating Lease PPAs
	(in millions)	
2019	$ 23	$ 64
2020	23	65
2021	24	66
2022	24	68
2023	25	69
2024 and thereafter	158	349
Total	$ 277	$ 681
Less: amounts representing executory costs[(a)]	42	
Net minimum lease payments	235	
Less: amounts representing interest[(b)]	105	
Present value of net minimum lease payments	$ 130	

(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.

See Note 8 under "Long-term Debt – Capital Leases – Georgia Power" for additional information.

Pipeline Charges, Storage Capacity, and Gas Supply

Southern Company Gas has commitments for pipeline charges, storage capacity, and gas supply, which include charges recoverable through natural gas cost recovery mechanisms, or alternatively, billed to marketers selling retail natural gas, as well as demand charges associated with Southern Company Gas' wholesale gas services. Gas supply commitments include amounts for gas commodity purchases associated with Southern Company Gas' gas marketing services of 47 million mmBtu at floating gas prices calculated using forward natural gas prices at December 31, 2018 and valued at $150 million. Southern Company Gas provides guarantees to certain gas suppliers for certain of its subsidiaries in support of payment obligations.

Southern Company Gas' expected future contractual obligations for pipeline charges, storage capacity, and gas supply that are not recognized on the balance sheets at December 31, 2018 were as follows:

	Pipeline Charges, Storage Capacity, and Gas Supply
	(in millions)
2019	$ 781
2020	584
2021	520
2022	489
2023	412
2024 and thereafter	1,871
Total	$ 4,657

Operating Leases

In addition to the operating lease PPAs discussed previously, the Southern Company system has operating lease agreements with various terms and expiration dates. The traditional electric operating companies' operating leases primarily relate to facilities, coal railcars, vehicles, cellular tower space, and other equipment. Southern Power's operating leases primarily relate to land for solar and wind facilities and are recognized on a straight-line basis over the minimum lease term, plus any renewal periods necessary to cover the expected life of the respective facility. Southern Company Gas' operating leases primarily relate to facilities and vehicles.

Total rent expense for 2018, 2017, and 2016 was as follows:

	Southern Company(*)	Alabama Power	Georgia Power	Mississippi Power	Southern Power(*)
			(in millions)		
2018	$ 192	$ 23	$ 34	$ 4	$ 31
2017	176	25	31	3	29
2016	169	18	28	3	22

(*) Includes contingent rent expense related to Southern Power's land leases based on wind production and escalation in the Consumer Price Index for All Urban Consumers.

	Southern Company Gas
	(in millions)
2018	$ 15
2017	15
Successor – July 1, 2016 through December 31, 2016	8
Predecessor – January 1, 2016 through June 30, 2016	6

The registrants exclude contingent rent but include any step rents, fixed escalations, lease concessions, and lease extensions to cover the expected life of the facility in the computation of minimum lease payments. At December 31, 2018, estimated minimum lease payments under operating leases were as follows:

	Southern Company	Alabama Power	Georgia Power	Mississippi Power	Southern Power	Southern Company Gas
			(in millions)			
2019	$ 156	$ 12	$ 23	$ 3	$ 23	$ 18
2020	134	10	18	2	24	16
2021	110	7	9	1	24	15
2022	98	6	6	1	24	13
2023	79	3	5	1	26	10
2024 and thereafter	1,040	1	13	2	874	34
Total	$ 1,617	$ 39	$ 74	$ 10	$ 995	$ 106

For the traditional electric operating companies, a majority of the railcar and barge lease expenses are recoverable through fuel cost recovery provisions.

In addition to the above rental commitments, Alabama Power and Georgia Power have potential obligations upon expiration of certain railcar leases with respect to the residual value of the leased property. These leases have terms expiring in 2023 for Alabama Power and in 2024 for Georgia Power with maximum obligations under these leases of $12 million for Alabama Power and $9 million for Georgia Power. At the termination of the leases, Alabama Power and Georgia Power may renew the leases, exercise their purchase options, 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, for Alabama Power, potentially eliminate the loss under the residual value obligations.

Guarantees

Alabama Power 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 and mature in June 2019. Alabama Power also guaranteed a $100 million principal amount long-term bank loan entered into by SEGCO on November 28, 2018. Georgia Power has agreed to reimburse Alabama Power for the portion of such obligations corresponding to Georgia Power's proportionate ownership of SEGCO's stock if Alabama Power is called upon to make such payment under its guarantee. At December 31, 2018, the capitalization of SEGCO consisted of $90 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 $5 million. See Note 7 under "SEGCO" for additional information.

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 agreement was subsequently amended on May 31, 2018. The guarantee is expected to be terminated if certain events occur by October 2019. In the event the gas supplier defaults on payments, the maximum potential exposure under the guarantee and amendment is approximately $30 million.

In October 2017, Atlantic Coast Pipeline executed a $3.4 billion revolving credit facility with a stated maturity date of October 2021. Southern Company Gas entered into a guarantee agreement to support its share of the revolving credit facility. Southern Company Gas' maximum exposure to loss under the terms of the guarantee is limited to 5% of the outstanding borrowings under the credit facility, and totaled $72 million as of December 31, 2018. See Note 2 under "FERC Matters – Southern Company Gas" for additional information regarding the Atlantic Coast Pipeline.

As discussed above under "Operating Leases," Alabama Power and Georgia Power have entered into certain residual value guarantees related to railcar leases.

10. INCOME TAXES

Southern Company files a consolidated federal income tax return and the registrants file 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. See Note 15 for additional information on these acquisitions, as well as disposition activity during 2018. In accordance with IRS regulations, each company is jointly and severally liable for the federal tax liability. Prior to the Merger, Southern Company Gas 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 provided 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 registrants considered all amounts recorded in the financial statements as a result of the Tax Reform Legislation "provisional" as discussed in SAB 118 and subject to revision prior to filing the 2017 tax return in the fourth quarter 2018. As of December 31, 2018, each of the registrants considered the measurement of impacts from the Tax Reform Legislation on deferred income tax assets and liabilities, primarily due to the impact of the reduction of the corporate income tax rate, to be complete.

However, the IRS continues to issue regulations that provide further interpretation and guidance on the law and each respective state's adoption of the provisions contained in the Tax Reform Legislation remains uncertain. In addition, the regulatory treatment of certain impacts of the Tax Reform Legislation is subject to the discretion of the FERC and each state regulatory commission. The ultimate impact of these matters cannot be determined at this time. See Note 2 for additional information.

Current and Deferred Income Taxes

Details of income tax provisions are as follows:

	2018				
	Southern Company	Alabama Power	Georgia Power	Mississippi Power	Southern Power
			(in millions)		
Federal —					
Current	$ 167	$ 91	$ 393	$ (567)	$ 85
Deferred	231	123	(249)	575	(154)
	398	214	144	8	(69)
State —					
Current	188	26	81	(10)	(9)
Deferred	(137)	51	(11)	(100)	(86)
	51	77	70	(110)	(95)
Total	$ 449	$ 291	$ 214	$ (102)	$ (164)

	2017				
	Southern Company	Alabama Power	Georgia Power	Mississippi Power	Southern Power
			(in millions)		
Federal —					
Current	$ (62)	$ 136	$ 256	$ 194	$ (566)
Deferred	(6)	336	504	(753)	(312)
	(68)	472	760	(559)	(878)
State —					
Current	37	23	116	—	(110)
Deferred	173	73	(46)	27	49
	210	96	70	27	(61)
Total	$ 142	$ 568	$ 830	$ (532)	$ (939)

	2016				
	Southern Company	Alabama Power	Georgia Power	Mississippi Power	Southern Power
			(in millions)		
Federal —					
Current	$ 1,184	$ 103	$ 391	$ (31)	$ 928
Deferred	(342)	339	319	(60)	(1,098)
	842	442	710	(91)	(170)
State —					
Current	(108)	20	6	(6)	(60)
Deferred	217	69	64	(7)	35
	109	89	70	(13)	(25)
Total	$ 951	$ 531	$ 780	$ (104)	$ (195)

	Southern Company Gas			
	Successor			Predecessor
	Year Ended December 31, 2018	Year Ended December 31, 2017	July 1, 2016 through December 31, 2016	January 1, 2016 through June 30, 2016
		(in millions)		*(in millions)*
Federal —				
Current	**$ 334**	$ 103	$ —	$ 67
Deferred	**33**	170	65	8
	367	273	65	75
State —				
Current	**131**	27	(16)	12
Deferred	**(34)**	67	27	—
	97	94	11	12
Total	**$ 464**	$ 367	$ 76	$ 87

Southern Company's and Southern Power's 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 in the tables above. Southern Power's ITCs and PTCs reclassified in this manner include $128 million for 2018, $316 million for

2017, and $1.13 billion for 2016. These ITCs and PTCs for Southern Company and Southern Power are included in "Deferred Tax Assets and Liabilities" herein.

In accordance with regulatory requirements, federal ITCs for the traditional electric operating companies and the natural gas distribution utilities, as well as certain state ITCs for Nicor Gas, 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. Southern Power's deferred federal ITCs are amortized to income tax expense over the life of the respective asset. ITCs amortized in 2018, 2017, and 2016 were immaterial for Alabama Power, Georgia Power, Mississippi Power, and Southern Company Gas and were as follows for Southern Company and Southern Power:

	Southern Company	Southern Power
	(in millions)	
2018	$ 87	$ 58
2017	79	57
2016	59	37

Southern Power received $5 million of cash related to federal ITCs under renewable energy initiatives in 2018. No cash was received in 2017 or 2016. Southern Power recognized tax credits and reduced the tax basis of the asset 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 $1 million in 2018, $18 million in 2017, and $173 million in 2016. See "Unrecognized Tax Benefits" herein for further information.

State ITCs and other state credits, which are recognized in the period in which the credits are generated, reduced Georgia Power's income tax expense by $21 million in 2018, $37 million in 2017, and $31 million in 2016 and reduced Southern Power's income tax expense by $32 million in 2017 and $7 million in 2016.

Southern Power's federal and state PTCs, which are recognized in the period in which the credits are generated, reduced Southern Power's income tax expense by $141 million in 2018, $139 million in 2017, and $50 million in 2016.

Legal Entity Reorganizations

In April 2018, Southern Power completed the final stage of 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. In September 2018, Southern Power also completed a legal entity reorganization of eight operating wind facilities under a new holding company, SP Wind. The reorganizations resulted in net state tax benefits related to certain changes in apportionment rates totaling approximately $65 million, which were recorded in 2018.

Effective Tax Rate

Southern Company's effective tax rate is typically lower than the statutory rate due to employee stock plans' dividend deduction, non-taxable AFUDC equity at the traditional electric operating companies, flowback of excess deferred income taxes at the regulated utilities, and federal income tax benefits from ITCs and PTCs primarily at Southern Power. Each registrant's effective tax rate for 2018 varied significantly as compared to 2017 due to the 14% lower 2018 federal tax rate resulting from the Tax Reform Legislation.

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

	2018				
	Southern Company	Alabama Power	Georgia Power	Mississippi Power	Southern Power
Federal statutory rate	**21.0%**	**21.0%**	**21.0%**	**21.0 %**	**21.0 %**
State income tax, net of federal deduction	**1.8**	**5.0**	**5.5**	**(65.1)**	**(90.8)**
Employee stock plans' dividend deduction	**(1.0)**	**—**	**—**	**—**	**—**
Non-deductible book depreciation	**0.8**	**0.6**	**1.2**	**0.7**	**—**
Flowback of excess deferred income taxes	**(4.0)**	**(1.8)**	**—**	**(4.1)**	**—**
AFUDC-Equity	**(1.0)**	**(1.0)**	**(1.4)**	**—**	**—**
ITC basis difference	**(0.6)**	**—**	**—**	**—**	**(0.2)**
Federal PTCs	**(4.7)**	**—**	**—**	**—**	**(156.6)**
Amortization of ITC	**(2.0)**	**(0.1)**	**(0.2)**	**(0.2)**	**(55.4)**
Tax impact from sale of subsidiaries	**8.6**	**—**	**—**	**—**	**—**
Tax Reform Legislation	**(1.4)**	**—**	**(4.9)**	**(26.3)**	**96.1**
Noncontrolling interests	**(0.4)**	**—**	**—**	**—**	**(14.9)**
Other	**(0.8)**	**(0.1)**	**0.1**	**(1.4)**	**2.0**
Effective income tax (benefit) rate	**16.3%**	**23.6%**	**21.3%**	**(75.4)%**	**(198.8)%**

	2017				
	Southern Company	Alabama Power	Georgia Power	Mississippi Power(*)	Southern Power
Federal statutory rate	35.0%	35.0%	35.0%	(35.0)%	35.0 %
State income tax, net of federal deduction	12.5	4.5	2.0	0.6	(22.2)
Employee stock plans' dividend deduction	(4.0)	—	—	—	—
Non-deductible book depreciation	3.1	0.9	0.7	0.1	—
Flowback of excess deferred income taxes	(0.3)	—	(0.1)	—	—
AFUDC-Equity	(2.6)	(1.0)	(0.6)	—	—
AFUDC-Equity portion of Kemper IGCC charge	15.7	—	—	5.3	—
ITC basis difference	(1.7)	—	—	—	(10.0)
Federal PTCs	(12.1)	—	—	—	(72.5)
Amortization of ITC	(4.2)	(0.2)	(0.1)	—	(20.6)
Tax Reform Legislation	(25.6)	0.3	(0.4)	11.9	(416.1)
Noncontrolling interests	(1.4)	—	—	—	(8.6)
Other	(1.1)	0.1	0.2	—	(10.7)
Effective income tax (benefit) rate	13.3%	39.6%	36.7%	(17.1)%	(525.7)%

(*) Represents effective income tax benefit rate for Mississippi Power due to a loss before income taxes in 2017.

COMBINED NOTES TO FINANCIAL STATEMENTS (continued)
Southern Company and Subsidiary Companies 2018 Annual Report

	2016				
	Southern Company	**Alabama Power**	**Georgia Power**	**Mississippi Power(*)**	**Southern Power**
Federal statutory rate	35.0%	35.0%	35.0%	(35.0)%	35.0 %
State income tax, net of federal deduction	2.0	4.2	2.1	(5.7)	(9.1)
Employee stock plans' dividend deduction	(1.2)	—	—	—	—
Non-deductible book depreciation	0.9	1.0	0.8	0.7	—
Flowback of excess deferred income taxes	(0.1)	—	(0.1)	(0.3)	—
AFUDC-Equity	(2.0)	(0.7)	(0.8)	(28.5)	—
ITC basis difference	(5.0)	—	—	—	(96.3)
Federal PTCs	(1.2)	—	—	—	(23.3)
Amortization of ITC	(0.9)	(0.2)	(0.2)	(0.1)	(13.4)
Noncontrolling interests	(0.3)	—	—	—	(6.2)
Other	0.1	(0.5)	(0.1)	0.4	4.7
Effective income tax (benefit) rate	27.3%	38.8%	36.7%	(68.5)%	(108.6)%

(*) Represents effective income tax benefit rate for Mississippi Power due to a loss before income taxes in 2016.

	Southern Company Gas			
	Successor			Predecessor
	Year Ended December 31, 2018	Year Ended December 31, 2017	July 1, 2016 through December 31, 2016	January 1, 2016 through June 30, 2016
Federal statutory rate	21.0%	35.0%	35.0%	35.0%
State income tax, net of federal deduction	9.2	10.0	3.6	3.5
Flowback of excess deferred income taxes	(3.0)	(0.2)	—	—
Amortization of ITC	(0.1)	(0.2)	(0.4)	—
Tax impact on sale of subsidiaries	28.5	—	—	—
Tax Reform Legislation	(0.4)	15.0	—	—
Other	0.3	0.6	1.8	(0.9)
Effective income tax rate	55.5%	60.2%	40.0%	37.6%

Deferred Tax Assets and Liabilities

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

	December 31, 2018					
	Southern Company	Alabama Power	Georgia Power	Mississippi Power	Southern Power	Southern Company Gas
			(in millions)			
Deferred tax liabilities —						
Accelerated depreciation	$ 8,461	$ 2,236	$ 3,005	$ 335	$ 1,483	$ 1,176
Property basis differences	1,807	865	633	162	—	134
Federal effect of net state deferred tax assets	—	—	—	36	—	—
Leveraged lease basis differences	253	—	—	—	—	—
Employee benefit obligations	477	149	290	25	6	6
Premium on reacquired debt	88	14	74	—	—	—
Regulatory assets –						
Storm damage reserves	111	—	111	—	—	—
Employee benefit obligations	975	260	344	45	—	45
AROs	1,232	276	925	31	—	—
AROs	1,210	607	575	—	—	—
Other	593	177	141	68	34	132
Total deferred income tax liabilities	15,207	4,584	6,098	702	1,523	1,493
Deferred tax assets —						
Federal effect of net state deferred tax liabilities	260	155	71	—	22	46
Employee benefit obligations	1,273	286	444	62	7	150
Other property basis differences	251	—	61	—	172	—
ITC and PTC carryforward	2,730	11	430	—	2,128	—
Alternative minimum tax carryforward	62	—	—	32	21	—
Other partnership basis difference	162	—	—	—	162	—
Other comprehensive losses	82	10	3	—	—	—
AROs	2,442	883	1,500	31	—	—
Estimated loss on plants under construction	346	—	283	63	—	—
Other deferred state tax attributes	415	—	19	251	72	—
Regulatory liability associated with the Tax Reform Legislation (not subject to normalization)	294	130	127	29	—	8
Other	731	147	140	47	47	285
Total deferred income tax assets	9,048	1,622	3,078	515	2,631	489
Valuation allowance	(123)	—	(42)	(41)	(27)	(12)
Net deferred income tax assets	8,925	1,622	3,036	474	2,604	477
Net deferred income taxes (assets)/liabilities	**$ 6,282**	**$ 2,962**	**$ 3,062**	**$ 228**	**$ (1,081)**	**$ 1,016**
Recognized in the balance sheets:						
Accumulated deferred income taxes – assets	**$ (276)**	**$ —**	**$ —**	**$ (150)**	**$ (1,186)**	**$ —**
Accumulated deferred income taxes – liabilities	**$ 6,558**	**$ 2,962**	**$ 3,062**	**$ 378**	**$ 105**	**$ 1,016**

	December 31, 2017					
	Southern Company	Alabama Power	Georgia Power	Mississippi Power	Southern Power	Southern Company Gas
			(in millions)			
Deferred tax liabilities —						
Accelerated depreciation	$ 9,059	$ 2,135	$ 2,889	$ 303	$ 1,922	$ 1,150
Property basis differences	1,853	725	606	207	2	204
Federal effect of net state deferred tax assets	—	—	—	9	—	—
Leveraged lease basis differences	251	—	—	—	—	—
Employee benefit obligations	527	162	287	28	7	4
Premium on reacquired debt	54	16	34	—	—	—
Regulatory assets –						
Storm damage reserves	89	—	89	—	—	—
Employee benefit obligations	1,044	260	349	46	—	75
AROs	821	249	501	33	—	—
AROs	370	220	130	—	—	—
Other	689	147	140	73	30	208
Total deferred income tax liabilities	14,757	3,914	5,025	699	1,961	1,641
Deferred tax assets —						
Federal effect of net state deferred tax liabilities	330	143	85	—	42	54
Employee benefit obligations	1,339	286	448	62	8	185
Other property basis differences	343	—	59	—	184	—
ITC and PTC carryforward	2,414	9	403	—	2,002	—
Federal NOL carryforward	518	—	—	40	333	92
Alternative minimum tax carryforward	69	—	—	32	21	—
Other partnership basis difference	23	—	—	—	23	—
Other comprehensive losses	84	10	4	—	1	—
AROs	1,191	469	631	33	—	—
Estimated loss on plants under construction	722	—	—	722	—	—
Other deferred state tax attributes	330	—	6	133	77	—
Regulatory liability associated with the Tax Reform Legislation (not subject to normalization)	304	126	123	27	—	9
Other	538	111	91	54	9	223
Total deferred income tax assets	8,205	1,154	1,850	1,103	2,700	563
Valuation allowance	(184)	—	—	(157)	(13)	(11)
Net deferred income tax assets	8,021	1,154	1,850	946	2,687	552
Net deferred income taxes (assets)/liabilities	**$ 6,736**	**$ 2,760**	**$ 3,175**	**$ (247)**	**$ (726)**	**$ 1,089**
Recognized in the balance sheets:						
Accumulated deferred income taxes – assets	**$ (106)**	**$ —**	**$ —**	**$ (247)**	**$ (925)**	**$ —**
Accumulated deferred income taxes – liabilities	**$ 6,842**	**$ 2,760**	**$ 3,175**	**$ —**	**$ 199**	**$ 1,089**

The implementation of the Tax Reform Legislation significantly reduced accumulated deferred income taxes in 2017, partially offset by bonus depreciation provisions in the PATH Act.

The traditional electric operating companies and natural gas distribution utilities have tax-related regulatory assets (deferred income tax charges) and regulatory liabilities (deferred income tax credits). The regulatory 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. The regulatory liabilities are primarily attributable to deferred taxes previously recognized at rates higher than the current enacted tax law and to unamortized ITCs. See Note 2 for each registrant's related balances at December 31, 2018 and 2017.

Tax Credit Carryforwards

Federal ITC/PTC carryforwards at December 31, 2018 were as follows:

	Southern Company	Alabama Power	Georgia Power	Southern Power
		(in millions)		
Federal ITC/PTC carryforwards	$ 2,410	$ 11	$ 108	$ 2,128
Year in which federal ITC/PTC carryforwards begin expiring	2032	2033	2032	2034
Year by which federal ITC/PTC carryforwards are expected to be utilized	2022	2021	2021	2022

The estimated tax credit utilization reflects the 2018 abandonment loss related to certain Kemper County energy facility expenditures as well as the projected taxable gains on the various sale transactions described in Note 15 and "Legal Entity Reorganizations" herein. The expected utilization of tax credit carryforwards could be further delayed by numerous factors, including the acquisition of additional renewable projects, the purchase of rights to additional PTCs of Plant Vogtle Units 3 and 4 pursuant to the MEAG Funding Agreement or the Global Amendments, and changes in taxable income projections. See Note 2 under "Georgia Power – Nuclear Construction" for additional information on Plant Vogtle Units 3 and 4.

At December 31, 2018, Georgia Power also had approximately $341 million in state investment and other state tax credit carryforwards for the State of Georgia that will expire between 2020 and 2028 and are not expected to be fully utilized. Georgia Power has a net state valuation allowance of $33 million associated with these carryforwards.

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

Net Operating Loss Carryforwards

In the 2018 tax year, Southern Company expects to fully utilize the carryforward from federal NOLs generated in 2016 and 2017.

At December 31, 2018, the state and local NOL carryforwards for Southern Company's subsidiaries were as follows:

Company/Jurisdiction	Approximate NOL Carryforwards	Approximate Net State Income Tax Benefit	Tax Year NOL Begins Expiring
	(in millions)		
Mississippi Power			
Mississippi	$ 5,062	$ 200	2031
Southern Power			
Oklahoma	846	40	2035
Florida	264	11	2033
South Carolina	62	2	2034
Other states	42	3	2029
Southern Power Total	$ 1,214	$ 56	
Other(*)			
Georgia	358	16	2019
New York	223	11	2036
New York City	208	15	2036
Other states	278	14	Various
Southern Company Total	$ 7,343	$ 312	

(*) Represents other Southern Company subsidiaries. Alabama Power, Georgia Power, and Southern Company Gas did not have state NOL carryforwards at December 31, 2018.

State NOLs for Mississippi, Oklahoma, and Florida are not expected to be fully utilized prior to expiration. At December 31, 2018, Mississippi Power had a net state valuation allowance of $32 million for the Mississippi NOL and Southern Power had a net state valuation allowance of $9 million for the Oklahoma NOL and $11 million for the Florida NOL.

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

Unrecognized Tax Benefits

Unrecognized tax benefits changes in 2018, 2017, and 2016 for Southern Company, Mississippi Power, and Southern Power are provided below. The remaining registrants did not have any material unrecognized tax benefits for the periods presented.

	Southern Company	Mississippi Power	Southern Power
		(in millions)	
Unrecognized tax benefits at December 31, 2015	**$ 433**	**$ 421**	**$ 8**
Tax positions changes –			
Increase from current periods	45	26	17
Increase from prior periods	21	18	—
Decrease from prior periods	(15)	—	(8)
Unrecognized tax benefits at December 31, 2016	**484**	**465**	**17**
Tax positions changes –			
Increase from current periods	10	—	—
Increase from prior periods	10	2	—
Decrease from prior periods	(196)	(177)	(17)
Reductions due to settlements	(290)	(290)	—
Unrecognized tax benefits at December 31, 2017	**18**	**—**	**—**
Tax positions changes –			
Decrease from prior periods	(18)	—	—
Unrecognized tax benefits at December 31, 2018	**$ —**	**$ —**	**$ —**

Mississippi Power's tax positions increase from current and prior periods for 2017 and 2016 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. Mississippi Power's tax positions decrease from prior periods and the reductions due to settlements for 2017 relate primarily to the settlement of R&E expenditures associated with the Kemper County energy facility. See Note 2 under "Mississippi Power – Kemper County Energy Facility" and "Section 174 Research and Experimental Deduction" herein for more information.

Southern Power's increase in unrecognized tax benefits from current periods for 2016, and the decrease from prior periods for 2017 and 2016, primarily relate to federal income tax benefits from deferred ITCs.

There were no unrecognized tax benefits at December 31, 2018. The impact on the effective tax rate of Southern Company, Mississippi Power, and Southern Power, if recognized, was as follows for 2017 and 2016:

	Southern Company	Mississippi Power	Southern Power
		(in millions)	
2017			
Tax positions impacting the effective tax rate	$ 18	$ —	$ —
Tax positions not impacting the effective tax rate	—	—	—
Balance of unrecognized tax benefits	$ 18	$ —	$ —
2016			
Tax positions impacting the effective tax rate	$ 20	$ 1	$ 17
Tax positions not impacting the effective tax rate	464	464	—
Balance of unrecognized tax benefits	$ 484	$ 465	$ 17

Mississippi Power's tax positions not impacting the effective tax rate for 2016 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.

Southern Power's impact on the effective tax rate was determined based on the amount of ITCs, which were uncertain.

All of the registrants classify interest on tax uncertainties as interest expense. Accrued interest for all tax positions other than the Section 174 R&E deductions was immaterial for all years presented. None of the registrants accrued any penalties on uncertain tax positions.

It is reasonably possible that the amount of the unrecognized tax benefits could change within 12 months. New audit findings or settlements associated with ongoing audits could result in significant unrecognized tax benefits. At this time, a range of reasonably possible outcomes cannot be determined.

The IRS has finalized its audits of Southern Company's consolidated federal income tax returns through 2017, as well as the pre-Merger Southern Company Gas tax returns. Southern Company is a participant in the Compliance Assurance Process of the IRS. The audits for the registrants' state income tax returns have either been concluded, or the statute of limitations has expired, for years prior to 2012.

Section 174 Research and Experimental Deduction

Southern Company, on behalf of Mississippi Power, 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 September 2017, the U.S. Congress Joint Committee on Taxation approved a settlement between Southern Company and the IRS, resolving a methodology for these deductions. As a result of this approval, Mississippi Power recognized $176 million in 2017 of previously unrecognized tax benefits and reversed $36 million of associated accrued interest.

11. RETIREMENT BENEFITS

The Southern Company system has a qualified defined benefit, trusteed, pension plan covering substantially all employees, with the exception of employees at PowerSecure. The qualified defined benefit 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, 2018 and no mandatory contributions to the qualified pension plan are anticipated for the year ending December 31, 2019. The Southern Company system also provides certain non-qualified defined benefits for a select group of management and highly compensated employees, which are funded on a cash basis. In addition, the Southern Company system provides certain medical care and life insurance benefits for retired employees through other postretirement benefit plans. The traditional electric operating companies fund other postretirement trusts to the extent required by their respective regulatory commissions. Southern Company Gas 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, 2019, no other postretirement trust contributions are expected.

On January 1, 2018, the qualified defined benefit pension plan of Southern Company Gas was merged into the Southern Company system's qualified defined benefit pension plan and the pension plan was reopened to all non-union employees of Southern Company Gas. Prior to January 1, 2018, Southern Company Gas had a separate qualified defined benefit, trusteed, pension plan covering certain eligible employees, which was closed in 2012 to new employees. Also on January 1, 2018, Southern Company Gas' non-qualified retirement plans were merged into the Southern Company system's non-qualified retirement plan (defined benefit and defined contribution).

Effective in December 2017, 538 employees transferred from SCS to Southern Power. Accordingly, Southern Power assumed various compensation and benefit plans including participation in the Southern Company system's qualified defined benefit, trusteed, pension plan covering substantially all employees. With the transfer of employees, Southern Power 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 in OCI. In 2018, Southern Power also began providing certain defined benefits under the 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 for services rendered by employees following the transfer are being recognized by Southern Power and are funded on a cash basis. In addition, Southern Power provides certain medical care and life insurance benefits for retired employees through other postretirement benefit plans that are 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 Southern Power's other operations and maintenance expense. The disclosures included herein exclude Southern Power for periods prior to the transfer of employees in December 2017.

On January 1, 2019, Southern Company completed the sale of Gulf Power to NextEra Energy. See Note 15 under "Southern Company's Sale of Gulf Power" for additional information. The portion of the Southern Company system's pension and other

postretirement benefit plans attributable to Gulf Power that is reflected in Southern Company's consolidated balance sheet as held for sale at December 31, 2018 consists of:

	Pension Plans	Other Postretirement Benefit Plans
	(in millions)	
Projected benefit obligation	$ 526	$ 69
Plan assets	492	17
Accrued liability	$ (34)	$ (52)

All amounts presented in the remainder of this note reflect the benefit plan obligations and related plan assets for the Southern Company system's pension and other postretirement benefit plans, including the amounts attributable to Gulf Power.

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.

	2018				
Assumptions used to determine net periodic costs:	**Southern Company**	**Alabama Power**	**Georgia Power**	**Mississippi Power**	**Southern Power**
Pension plans					
Discount rate – benefit obligations	**3.80%**	**3.81%**	**3.79%**	**3.80%**	**3.94%**
Discount rate – interest costs	**3.45**	**3.45**	**3.42**	**3.46**	**3.69**
Discount rate – service costs	**3.98**	**4.00**	**3.99**	**3.99**	**4.01**
Expected long-term return on plan assets	**7.95**	**7.95**	**7.95**	**7.95**	**7.95**
Annual salary increase	**4.34**	**4.46**	**4.46**	**4.46**	**4.46**
Other postretirement benefit plans					
Discount rate – benefit obligations	**3.68%**	**3.71%**	**3.68%**	**3.68%**	**3.81%**
Discount rate – interest costs	**3.29**	**3.31**	**3.29**	**3.29**	**3.47**
Discount rate – service costs	**3.91**	**3.93**	**3.91**	**3.91**	**3.93**
Expected long-term return on plan assets	**6.83**	**6.83**	**6.80**	**6.99**	**—**
Annual salary increase	**4.34**	**4.46**	**4.46**	**4.46**	**4.46**

Assumptions used to determine net periodic costs:	2017 Southern Company	Alabama Power	Georgia Power	Mississippi Power
Pension plans				
Discount rate – benefit obligations	4.40%	4.44%	4.40%	4.44%
Discount rate – interest costs	3.77	3.76	3.72	3.81
Discount rate – service costs	4.81	4.85	4.83	4.83
Expected long-term return on plan assets	7.92	7.95	7.95	7.95
Annual salary increase	4.37	4.46	4.46	4.46
Other postretirement benefit plans				
Discount rate – benefit obligations	4.23%	4.27%	4.23%	4.22%
Discount rate – interest costs	3.54	3.58	3.55	3.55
Discount rate – service costs	4.64	4.70	4.63	4.65
Expected long-term return on plan assets	6.84	6.83	6.79	6.88
Annual salary increase	4.37	4.46	4.46	4.46

Assumptions used to determine net periodic costs:	2016 Southern Company	Alabama Power	Georgia Power	Mississippi Power
Pension plans				
Discount rate – benefit obligations	4.58%	4.67%	4.65%	4.69%
Discount rate – interest costs	3.88	3.90	3.86	3.97
Discount rate – service costs	4.98	5.07	5.03	5.04
Expected long-term return on plan assets	8.16	8.20	8.20	8.20
Annual salary increase	4.37	4.46	4.46	4.46
Other postretirement benefit plans				
Discount rate – benefit obligations	4.38%	4.51%	4.49%	4.47%
Discount rate – interest costs	3.66	3.69	3.67	3.66
Discount rate – service costs	4.85	4.96	4.88	4.88
Expected long-term return on plan assets	6.66	6.83	6.27	7.07
Annual salary increase	4.37	4.46	4.46	4.46

Assumptions used to determine net periodic costs:	Southern Company Gas			
	Successor			Predecessor
	Year Ended December 31, 2018	Year Ended December 31, 2017	July 1, 2016 through December 31, 2016	January 1, 2016 through June 30, 2016
Pension plans				
Discount rate – benefit obligations	**3.74%**	4.39%	3.85%	4.60%
Discount rate – interest costs	**3.41**	3.76	3.21	4.00
Discount rate – service costs	**3.84**	4.64	4.07	4.80
Expected long-term return on plan assets	**7.95**	7.60	7.75	7.80
Annual salary increase	**3.07**	3.50	3.50	3.70
Pension band increase(*)	**N/A**	N/A	2.00	2.00
Other postretirement benefit plans				
Discount rate - benefit obligations	**3.62%**	4.15%	3.61%	4.40%
Discount rate – interest costs	**3.21**	3.40	2.84	3.60
Discount rate – service costs	**3.82**	4.55	3.96	4.70
Expected long-term return on plan assets	**5.89**	6.03	5.93	6.60
Annual salary increase	**3.07**	3.50	3.50	3.70

(*) Only applicable to Nicor Gas union employees. The pension bands for the former Nicor Gas plan reflect the negotiated rates in accordance with the union agreements.

Assumptions used to determine benefit obligations:	2018					
	Southern Company	Alabama Power	Georgia Power	Mississippi Power	Southern Power	Southern Company Gas
Pension plans						
Discount rate	**4.49%**	**4.51%**	**4.48%**	**4.49%**	**4.65%**	**4.47%**
Annual salary increase	**4.34**	**4.46**	**4.46**	**4.46**	**4.46**	**3.07**
Other postretirement benefit plans						
Discount rate	**4.37%**	**4.40%**	**4.36%**	**4.35%**	**4.50%**	**4.32%**
Annual salary increase	**4.34**	**4.46**	**4.46**	**4.46**	**4.46**	**3.07**

Assumptions used to determine benefit obligations:	2017					
	Southern Company	Alabama Power	Georgia Power	Mississippi Power	Southern Power	Southern Company Gas
Pension plans						
Discount rate	3.80%	3.81%	3.79%	3.80%	3.94%	3.74%
Annual salary increase	4.32	4.46	4.46	4.46	4.46	2.88
Other postretirement benefit plans						
Discount rate	3.68%	3.71%	3.68%	3.68%	3.81%	3.62%
Annual salary increase	4.32	4.46	4.46	4.46	4.46	2.56

The registrants estimate 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 the 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 for the registrants at December 31, 2018 were as follows:

	Initial Cost Trend Rate	Ultimate Cost Trend Rate	Year That Ultimate Rate is Reached
Pre-65	6.50%	4.50%	2028
Post-65 medical	5.00	4.50	2028
Post-65 prescription	8.00	4.50	2028

Pension Plans

The total accumulated benefit obligation for the pension plans at December 31, 2018 and 2017 was as follows:

	Southern Company	Alabama Power	Georgia Power	Mississippi Power	Southern Power	Southern Company Gas
			(in millions)			
December 31, 2018	$ 11,683	$ 2,550	$ 3,613	$ 513	$ 101	$ 842
December 31, 2017	12,577	2,696	3,847	541	111	1,139

The actuarial gain of $1.1 billion recorded in the remeasurement of the Southern Company system pension plans at December 31, 2018 was primarily due to a 69 basis point increase in the overall discount rate used to calculate the benefit obligation as a result of higher market interest rates. The actuarial loss of $1.3 billion recorded in the remeasurement of the Southern Company system pension plans at December 31, 2017 was primarily due to a 60 basis point decrease in the overall discount rate used to calculate the benefit obligation as a result of lower market interest rates.

Changes in the projected benefit obligations and the fair value of plan assets during the plan years ended December 31, 2018 and 2017 were as follows:

	2018					
	Southern Company	Alabama Power	Georgia Power	Mississippi Power	Southern Power	Southern Company Gas
			(in millions)			
Change in benefit obligation						
Benefit obligation at beginning of year	**$ 13,808**	**$ 2,998**	**$ 4,188**	**$ 602**	**$ 139**	**$ 1,184**
Dispositions	**(107)**	**—**	**—**	**—**	**(3)**	**(104)**
Service cost	**359**	**78**	**87**	**17**	**9**	**34**
Interest cost	**464**	**101**	**139**	**20**	**5**	**39**
Benefits paid	**(618)**	**(124)**	**(191)**	**(24)**	**(3)**	**(98)**
Actuarial (gain) loss	**(1,143)**	**(237)**	**(318)**	**(58)**	**(24)**	**(148)**
Balance at end of year	**12,763**	**2,816**	**3,905**	**557**	**123**	**907**
Change in plan assets						
Fair value of plan assets at beginning of year	**12,992**	**2,836**	**4,058**	**563**	**138**	**1,068**
Dispositions	**(107)**	**—**	**—**	**—**	**(3)**	**(104)**
Actual return (loss) on plan assets	**(711)**	**(150)**	**(218)**	**(37)**	**(9)**	**(70)**
Employer contributions	**55**	**13**	**14**	**3**	**—**	**2**
Benefits paid	**(618)**	**(124)**	**(191)**	**(24)**	**(3)**	**(98)**
Fair value of plan assets at end of year	**11,611**	**2,575**	**3,663**	**505**	**123**	**798**
Accrued liability	**$ (1,152)**	**$ (241)**	**$ (242)**	**$ (52)**	**$ —**	**$ (109)**

	2017					
	Southern Company	Alabama Power	Georgia Power	Mississippi Power	Southern Power	Southern Company Gas
			(in millions)			
Change in benefit obligation						
Benefit obligation at beginning of year	$ 12,385	$ 2,663	$ 3,800	$ 534	$ —	$ 1,133
Service cost	293	63	74	15	—	23
Interest cost	455	98	138	20	—	42
Benefits paid	(596)	(120)	(187)	(22)	—	(91)
Plan amendments	(26)	—	—	—	—	(26)
Actuarial (gain) loss	1,297	294	363	55	—	103
Obligations assumed from employee transfer	—	—	—	—	139	—
Balance at end of year	13,808	2,998	4,188	602	139	1,184
Change in plan assets						
Fair value of plan assets at beginning of year	11,583	2,517	3,621	499	—	983
Actual return (loss) on plan assets	1,953	427	610	84	—	175
Employer contributions	52	12	14	2	—	1
Benefits paid	(596)	(120)	(187)	(22)	—	(91)
Assets assumed from employee transfer	—	—	—	—	138	—
Fair value of plan assets at end of year	12,992	2,836	4,058	563	138	1,068
Accrued liability	$ (816)	$ (162)	$ (130)	$ (39)	$ (1)	$ (116)

The projected benefit obligations for the qualified and non-qualified pension plans at December 31, 2018 are shown in the following table. All pension plan assets are related to the qualified pension plan.

	Southern Company	Alabama Power	Georgia Power	Mississippi Power	Southern Power	Southern Company Gas
			(in millions)			
Projected benefit obligations:						
Qualified pension plan	$ 12,135	$ 2,692	$ 3,757	$ 527	$ 122	$ 866
Non-qualified pension plan	629	124	148	30	1	41

Amounts recognized in the balance sheets at December 31, 2018 and 2017 related to the registrants' pension plans consist of the following:

	Southern Company(*)	Alabama Power	Georgia Power	Mississippi Power	Southern Power	Southern Company Gas
			(in millions)			
December 31, 2018:						
Prepaid pension costs	$ —	$ —	$ —	$ —	$ 1	$ —
Other regulatory assets, deferred	**3,566**	**955**	**1,230**	**167**	**—**	**160**
Other deferred charges and assets	**—**	**—**	**—**	**—**	**—**	**74**
Other current liabilities	**(55)**	**(12)**	**(15)**	**(3)**	**—**	**(3)**
Employee benefit obligations	**(1,097)**	**(229)**	**(227)**	**(49)**	**(1)**	**(179)**
Other regulatory liabilities, deferred	**(108)**	**—**	**—**	**—**	**—**	**—**
AOCI	**97**	**—**	**—**	**—**	**26**	**(44)**
December 31, 2017:						
Prepaid pension costs	$ —	$ —	$ 23	$ —	$ —	$ —
Other regulatory assets, deferred	3,273	890	1,105	158	—	217
Other deferred charges and assets	—	—	—	—	—	85
Other current liabilities	(53)	(12)	(15)	(3)	—	(3)
Employee benefit obligations	(763)	(150)	(138)	(36)	(1)	(198)
Other regulatory liabilities, deferred	(118)	—	—	—	—	—
AOCI	107	—	—	—	33	(42)

(*) Amounts for Southern Company exclude regulatory assets of $268 million associated with unamortized amounts in Southern Company Gas' pension plans prior to its acquisition by Southern Company on July 1, 2016.

Presented below are the amounts included in regulatory assets at December 31, 2018 and 2017 related to the portion of the defined benefit pension plan attributable to Southern Company, the traditional electric operating companies, and Southern Company Gas that had not yet been recognized in net periodic pension cost.

	Southern Company(*)	Alabama Power	Georgia Power	Mississippi Power	Southern Company Gas
			(in millions)		
Balance at December 31, 2018					
Regulatory assets:					
Prior service cost	**$ 17**	**$ 6**	**$ 12**	**$ 2**	**$ (17)**
Net (gain) loss	**3,441**	**949**	**1,218**	**165**	**83**
Regulatory amortization(*)	**—**	**—**	**—**	**—**	**94**
Total regulatory assets (liabilities)	**$ 3,458**	**$ 955**	**$ 1,230**	**$ 167**	**$ 160**
Balance at December 31, 2017					
Regulatory assets:					
Prior service cost	$ 14	$ 8	$ 14	$ 3	$ (20)
Net (gain) loss	3,140	882	1,091	155	197
Regulatory amortization(*)	—	—	—	—	40
Total regulatory assets	$ 3,154	$ 890	$ 1,105	$ 158	$ 217

(*) Amounts for Southern Company exclude regulatory assets of $268 million associated with unamortized amounts in Southern Company Gas' pension plans prior to its acquisition by Southern Company on July 1, 2016.

The changes in the balance of regulatory assets related to the portion of the defined benefit pension plan attributable to Southern Company, the traditional electric operating companies, and Southern Company Gas for the years ended December 31, 2018 and 2017 are presented in the following table:

	Southern Company(*)	Alabama Power	Georgia Power	Mississippi Power	Southern Company Gas
			(in millions)		
Regulatory assets (liabilities):					
Balance at December 31, 2016	$ 3,120	$ 870	$ 1,129	$ 154	$ 267
Net (gain) loss	227	64	36	12	(31)
Change in prior service costs	(26)	—	—	—	—
Reclassification adjustments:					
Amortization of prior service costs	(11)	(2)	(3)	(1)	—
Amortization of net gain (loss)	(155)	(42)	(57)	(7)	(18)
Amortization of regulatory assets(*)	—	—	—	—	(1)
Total reclassification adjustments	(166)	(44)	(60)	(8)	(19)
Total change	35	20	(24)	4	(50)
Balance at December 31, 2017	$ 3,155	$ 890	$ 1,105	$ 158	$ 217
Net (gain) loss	**498**	**120**	**196**	**19**	**20**
Change in prior service costs	**1**	**—**	**—**	**—**	**(18)**
Dispositions	**12**	**—**	**—**	**—**	**(34)**
Reclassification adjustments:					
Amortization of prior service costs	**(4)**	**(1)**	**(2)**	**—**	**2**
Amortization of net gain (loss)	**(204)**	**(54)**	**(69)**	**(10)**	**(12)**
Amortization of regulatory assets	**—**	**—**	**—**	**—**	**(15)**
Total reclassification adjustments	**(208)**	**(55)**	**(71)**	**(10)**	**(25)**
Total change	**303**	**65**	**125**	**9**	**(57)**
Balance at December 31, 2018	**$ 3,458**	**$ 955**	**$ 1,230**	**$ 167**	**$ 160**

(*) Amounts for Southern Company exclude regulatory assets of $268 million associated with unamortized amounts in Southern Company Gas' pension plans prior to its acquisition by Southern Company on July 1, 2016.

Presented below are the amounts included in AOCI at December 31, 2018 and 2017 related to the portion of the defined benefit pension plan attributable to Southern Company, Southern Power, and Southern Company Gas that had not yet been recognized in net periodic pension cost.

	Southern Company	Southern Power	Southern Company Gas
		(in millions)	
Balance at December 31, 2018			
AOCI:			
Prior service cost	**$ (3)**	**$ —**	**$ (6)**
Net (gain) loss	**100**	**26**	**(38)**
Total AOCI	**$ 97**	**$ 26**	**$ (44)**
Balance at December 31, 2017			
AOCI:			
Prior service cost	$ 3	$ 1	$ —
Net (gain) loss	104	32	(42)
Total AOCI	$ 107	$ 33	$ (42)

The components of OCI related to the portion of the defined benefit pension plan attributable to Southern Company, Southern Power, and Southern Company Gas for the years ended December 31, 2018 and 2017 are presented in the following table:

	Southern Company	Southern Power	Southern Company Gas
		(in millions)	
AOCI:			
Balance at December 31, 2016	$ 100	$ —	$ (43)
Net (gain) loss	15	—	1
Change from employee transfer	—	33	—
Reclassification adjustments:			
Amortization of prior service costs	(1)	—	—
Amortization of net gain (loss)	(7)	—	—
Total reclassification adjustments	(8)	—	—
Total change	7	33	1
Balance at December 31, 2017	$ 107	$ 33	$ (42)
Net (gain) loss	**7**	**(5)**	**6**
Dispositions	**(8)**	**—**	**(8)**
Reclassification adjustments:			
Amortization of net gain (loss)	**(9)**	**(2)**	**—**
Total reclassification adjustments	**(9)**	**(2)**	**—**
Total change	**(10)**	**(7)**	**(2)**
Balance at December 31, 2018	**$ 97**	**$ 26**	**$ (44)**

Components of net periodic pension cost for Southern Company, the traditional electric operating companies, and Southern Power were as follows:

	Southern Company	Alabama Power	Georgia Power	Mississippi Power	Southern Power
			(in millions)		
2018:					
Service cost	**$ 359**	**$ 78**	**$ 87**	**$ 17**	**$ 9**
Interest cost	**464**	**101**	**139**	**20**	**5**
Expected return on plan assets	**(943)**	**(207)**	**(296)**	**(41)**	**(10)**
Recognized net (gain) loss	**213**	**54**	**69**	**10**	**1**
Net amortization	**4**	**1**	**2**	**—**	**—**
Net periodic pension cost	**$ 97**	**$ 27**	**$ 1**	**$ 6**	**$ 5**
2017:					
Service cost	$ 293	$ 63	$ 74	$ 15	
Interest cost	455	98	138	20	
Expected return on plan assets	(897)	(196)	(283)	(40)	
Recognized net (gain) loss	162	42	57	7	
Net amortization	12	2	3	1	
Net periodic pension cost	$ 25	$ 9	$ (11)	$ 3	
2016:					
Service cost	$ 262	$ 57	$ 70	$ 13	
Interest cost	422	95	136	19	
Expected return on plan assets	(782)	(184)	(258)	(35)	
Recognized net (gain) loss	150	40	55	7	
Net amortization	14	3	5	1	
Net periodic pension cost	$ 66	$ 11	$ 8	$ 5	

Components of net periodic pension cost for Southern Company Gas were as follows:

	Southern Company Gas			
	Successor			Predecessor
	Year Ended December 31, 2018	**Year Ended December 31, 2017**	**July 1, 2016 through December 31, 2016**	**January 1, 2016 through June 30, 2016**
		(in millions)		*(in millions)*
Service cost	**$ 34**	$ 23	$ 15	$ 13
Interest cost	**39**	42	20	21
Expected return on plan assets	**(75)**	(70)	(35)	(33)
Recognized net (gain) loss	**12**	18	14	13
Net amortization of regulatory asset	**15**	1	—	—
Prior service cost	**(2)**	—	(1)	(1)
Net periodic pension cost	**$ 23**	$ 14	$ 13	$ 13

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 registrants have 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, 2018, estimated benefit payments were as follows:

	Southern Company	Alabama Power	Georgia Power	Mississippi Power	Southern Power	Southern Company Gas
			(in millions)			
Benefit Payments:						
2019	$ 623	$ 132	$ 201	$ 28	$ 3	$ 59
2020	645	136	206	28	3	61
2021	664	141	209	29	4	62
2022	687	147	215	29	4	62
2023	711	152	221	30	5	62
2024 to 2028	3,869	832	1,183	166	27	313

Other Postretirement Benefits

Changes in the APBO and the fair value of the registrants' plan assets during the plan years ended December 31, 2018 and 2017 were as follows:

	2018					
	Southern Company	Alabama Power	Georgia Power	Mississippi Power	Southern Power	Southern Company Gas
			(in millions)			
Change in benefit obligation						
Benefit obligation at beginning of year	**$ 2,339**	**$ 517**	**$ 863**	**$ 97**	**$ 11**	**$ 310**
Dispositions	**(18)**	**—**	**—**	**—**	**—**	**(18)**
Service cost	**24**	**6**	**6**	**1**	**1**	**2**
Interest cost	**75**	**17**	**28**	**3**	**—**	**10**
Benefits paid	**(129)**	**(28)**	**(47)**	**(5)**	**(1)**	**(17)**
Actuarial (gain) loss	**(432)**	**(111)**	**(178)**	**(15)**	**(2)**	**(43)**
Retiree drug subsidy	**6**	**2**	**3**	**—**	**—**	**—**
Balance at end of year	**1,865**	**403**	**675**	**81**	**9**	**244**
Change in plan assets						
Fair value of plan assets at beginning of year	**1,053**	**406**	**386**	**25**	**—**	**125**
Dispositions	**(18)**	**—**	**—**	**—**	**—**	**(18)**
Actual return (loss) on plan assets	**(57)**	**(25)**	**(20)**	**(1)**	**—**	**(5)**
Employer contributions	**73**	**5**	**22**	**4**	**1**	**13**
Benefits paid	**(123)**	**(26)**	**(44)**	**(5)**	**(1)**	**(17)**
Fair value of plan assets at end of year	**928**	**360**	**344**	**23**	**—**	**98**
Accrued liability	**$ (937)**	**$ (43)**	**$ (331)**	**$ (58)**	**$ (9)**	**$ (146)**

	2017					
	Southern Company	Alabama Power	Georgia Power	Mississippi Power	Southern Power	Southern Company Gas
			(in millions)			
Change in benefit obligation						
Benefit obligation at beginning of year	$ 2,297	$ 501	$ 847	$ 97	$ —	$ 308
Service cost	24	6	7	1	—	2
Interest cost	79	17	29	3	—	10
Benefits paid	(136)	(29)	(51)	(6)	—	(19)
Actuarial (gain) loss	65	20	28	1	—	3
Plan amendments	3	—	—	—	—	3
Retiree drug subsidy	7	2	3	1	—	—
Obligations assumed from employee transfer	—	—	—	—	11	—
Employee contributions	—	—	—	—	—	3
Balance at end of year	2,339	517	863	97	11	310
Change in plan assets						
Fair value of plan assets at beginning of year	944	367	354	23	—	105
Actual return (loss) on plan assets	154	60	54	3	—	20
Employer contributions	84	6	26	4	—	17
Employee contributions	—	—	—	—	—	3
Benefits paid	(129)	(27)	(48)	(5)	—	(20)
Fair value of plan assets at end of year	1,053	406	386	25	—	125
Accrued liability	$ (1,286)	$ (111)	$ (477)	$ (72)	$ (11)	$ (185)

Amounts recognized in the balance sheets at December 31, 2018 and 2017 related to the registrants' other postretirement benefit plans consist of the following:

	Southern Company[a]	Alabama Power	Georgia Power	Mississippi Power	Southern Power	Southern Company Gas
			(in millions)			
December 31, 2018:						
Other regulatory assets, deferred[a]	**$ 99**	**$ —**	**$ 60**	**$ 6**	**$ —**	**$ (4)**
Other current liabilities	**(6)**	**—**	**—**	**—**	**—**	**—**
Employee benefit obligations[b]	**(931)**	**(43)**	**(331)**	**(58)**	**(9)**	**146**
Other regulatory liabilities, deferred	**(77)**	**(8)**	**—**	**(2)**	**—**	**—**
AOCI	**(4)**	**—**	**—**	**—**	**1**	**(4)**
December 31, 2017:						
Other regulatory assets, deferred[a]	$ 382	$ 63	$ 202	$ 18	$ —	$ 46
Other current liabilities	(5)	—	—	—	—	—
Employee benefit obligations[b]	(1,281)	(111)	(477)	(72)	(11)	(185)
Other regulatory liabilities, deferred	(41)	(7)	—	(1)	—	—
AOCI	4	—	—	—	3	(3)

(a) Amounts for Southern Company exclude regulatory assets of $57 million associated with unamortized amounts in Southern Company Gas' other postretirement benefit plans prior to its acquisition by Southern Company on July 1, 2016.

(b) Included in other deferred credits and liabilities on Southern Power's consolidated balance sheets.

COMBINED NOTES TO FINANCIAL STATEMENTS (continued)
Southern Company and Subsidiary Companies 2018 Annual Report

Presented below are the amounts included in net regulatory assets (liabilities) at December 31, 2018 and 2017 related to the other postretirement benefit plans of Southern Company, the traditional electric operating companies, and Southern Company Gas that had not yet been recognized in net periodic other postretirement benefit cost.

	Southern Company(*)	Alabama Power	Georgia Power	Mississippi Power	Southern Company Gas
			(in millions)		
Balance at December 31, 2018					
Regulatory assets:					
Prior service cost	**$ 14**	**$ 8**	**$ 4**	**$ —**	**$ 2**
Net (gain) loss	**8**	**(16)**	**56**	**4**	**(43)**
Regulatory amortization(*)	**—**	**—**	**—**	**—**	**37**
Total regulatory assets (liabilities)	**$ 22**	**$ (8)**	**$ 60**	**$ 4**	**$ (4)**
Balance at December 31, 2017					
Regulatory assets:					
Prior service cost	$ 21	$ 11	$ 5	$ —	$ (7)
Net (gain) loss	320	45	197	17	47
Regulatory amortization(*)	—	—	—	—	6
Total regulatory assets	$ 341	$ 56	$ 202	$ 17	$ 46

(*) Amounts for Southern Company exclude regulatory assets of $57 million associated with unamortized amounts in Southern Company Gas' other postretirement benefit plans prior to its acquisition by Southern Company on July 1, 2016.

The changes in the balance of net regulatory assets (liabilities) related to the other postretirement benefit plans for the plan years ended December 31, 2018 and 2017 are presented in the following table:

	Southern Company(*)	Alabama Power	Georgia Power	Mississippi Power	Southern Company Gas
			(in millions)		
Net regulatory assets (liabilities):					
Balance at December 31, 2016	$ 378	$ 76	$ 213	$ 19	$ 52
Net (gain) loss	(21)	(15)	(2)	(1)	(5)
Change in prior service costs	3	—	—	—	—
Reclassification adjustments:					
Amortization of prior service costs	(6)	(4)	(1)	—	3
Amortization of net gain (loss)	(13)	(1)	(8)	(1)	(4)
Total reclassification adjustments	(19)	(5)	(9)	(1)	(1)
Total change	(37)	(20)	(11)	(2)	(6)
Balance at December 31, 2017	$ 341	$ 56	$ 202	$ 17	$ 46
Net (gain) loss	(298)	(60)	(132)	(12)	(42)
Change in prior service costs	—	—	—	—	(2)
Reclassification adjustments:					
Amortization of prior service costs	(7)	(4)	(1)	—	—
Amortization of net gain (loss)	(14)	(1)	(9)	(1)	—
Amortization of regulatory assets	—	—	—	—	(6)
Total reclassification adjustments	(21)	(5)	(10)	(1)	(6)
Total change	(319)	(65)	(142)	(13)	(50)
Balance at December 31, 2018	$ 22	$ (9)	$ 60	$ 4	$ (4)

(*) Amounts for Southern Company exclude regulatory assets of $57 million associated with unamortized amounts in Southern Company Gas' other postretirement benefit plans prior to its acquisition by Southern Company on July 1, 2016.

Presented below are the amounts included in AOCI at December 31, 2018 and 2017 related to the other postretirement benefit plans of Southern Company, Southern Power, and Southern Company Gas that had not yet been recognized in net periodic other postretirement benefit cost.

	Southern Company	Southern Power	Southern Company Gas
		(in millions)	
Balance at December 31, 2018			
AOCI:			
Prior service cost	**$ 1**	**$ —**	**$ 1**
Net (gain) loss	**(5)**	**1**	**(5)**
Total AOCI	**$ (4)**	**$ 1**	**$ (4)**
Balance at December 31, 2017			
AOCI:			
Prior service cost	$ —	$ —	$ —
Net (gain) loss	4	3	(3)
Total AOCI	$ 4	$ 3	$ (3)

The components of OCI related to the other postretirement benefit plans for the plan years ended December 31, 2018 and 2017 are presented in the following table:

	Southern Company	Southern Power	Southern Company Gas
		(in millions)	
AOCI:			
Balance at December 31, 2016	$ 7	$ —	$ (3)
Net (gain) loss	(3)	—	(1)
Change from employee transfer	—	3	1
Total change	(3)	3	—
Balance at December 31, 2017	$ 4	$ 3	$ (3)
Net (gain) loss	(8)	(2)	(2)
Amortization of prior service costs	—	—	1
Total change	(8)	(2)	(1)
Balance at December 31, 2018	$ (4)	$ 1	$ (4)

Components of the other postretirement benefit plans' net periodic cost for Southern Company, the traditional electric operating companies, and Southern Power were as follows:

	Southern Company	Alabama Power	Georgia Power	Mississippi Power	Southern Power
			(in millions)		
2018:					
Service cost	**$ 24**	**$ 6**	**$ 6**	**$ 1**	**$ 1**
Interest cost	**75**	**17**	**28**	**3**	**—**
Expected return on plan assets	**(69)**	**(26)**	**(25)**	**(2)**	**—**
Net amortization	**21**	**5**	**10**	**1**	**—**
Net periodic postretirement benefit cost	**$ 51**	**$ 2**	**$ 19**	**$ 3**	**$ 1**
2017:					
Service cost	$ 24	$ 6	$ 7	$ 1	
Interest cost	79	17	29	3	
Expected return on plan assets	(66)	(25)	(25)	(1)	
Net amortization	20	5	9	1	
Net periodic postretirement benefit cost	$ 57	$ 3	$ 20	$ 4	
2016:					
Service cost	$ 22	$ 5	$ 6	$ 1	
Interest cost	76	18	30	3	
Expected return on plan assets	(60)	(25)	(22)	(1)	
Net amortization	21	6	10	1	
Net periodic postretirement benefit cost	$ 59	$ 4	$ 24	$ 4	

Components of the other postretirement benefit plans' net periodic cost for Southern Company Gas were as follows:

	Successor			Predecessor
	Year Ended December 31, 2018	**Year Ended December 31, 2017**	**July 1, 2016 through December 31, 2016**	**January 1, 2016 through June 30, 2016**
	(in millions)			*(in millions)*
Service cost	**$ 2**	$ 2	$ 1	$ 1
Interest cost	**10**	10	5	5
Expected return on plan assets	**(7)**	(7)	(3)	(3)
Amortization:				
Regulatory assets	**6**	—	2	—
Prior service costs	**—**	(3)	—	(1)
Net (gain)/loss	**—**	4	—	2
Net periodic postretirement benefit cost	**$ 11**	$ 6	$ 5	$ 4

The registrants' 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. The registrants' 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:

	Southern Company	**Alabama Power**	**Georgia Power**	**Mississippi Power**	**Southern Power**	**Southern Company Gas**
			(in millions)			
Benefit payments:						
2019	$ 136	$ 28	$ 51	$ 6	$ —	$ 18
2020	136	28	50	6	—	18
2021	136	29	50	6	—	19
2022	137	29	50	6	1	19
2023	137	29	49	7	1	19
2024 to 2028	669	146	243	30	3	90
Subsidy receipts:						
2019	$ (7)	$ (2)	$ (3)	$ —	$ —	$ —
2020	(7)	(2)	(3)	—	—	—
2021	(8)	(2)	(3)	—	—	—
2022	(8)	(2)	(3)	(1)	—	—
2023	(8)	(3)	(4)	(1)	—	—
2024 to 2028	(41)	(13)	(18)	(2)	—	—
Total:						
2019	$ 129	$ 26	$ 48	$ 6	$ —	$ 18
2020	129	26	47	6	—	18
2021	128	27	47	6	—	19
2022	129	27	47	5	1	19
2023	129	26	45	6	1	19
2024 to 2028	628	133	225	28	3	90

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. The registrants' 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 registrants minimize the risk of large losses primarily through diversification but also monitor and manage other aspects of risk.

The investment strategy for plan assets related to the Southern Company system'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 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 system employs a formal rebalancing program. As additional risk management, external investment managers and service providers are subject to written guidelines to ensure appropriate and prudent investment practices. Management believes the portfolio is well-diversified with no significant concentrations of risk.

Investment Strategies and Benefit Plan Asset Fair Values

A description of the major asset classes that the pension and other postretirement benefit plans are comprised of, along with the valuation methods used for fair value measurement, is provided below:

Description	Valuation Methodology
Domestic equity: A mix of large and small capitalization stocks with generally an equal distribution of value and growth attributes, managed both actively and through passive index approaches. **International equity:** A mix of growth stocks and value stocks with both developed and emerging market exposure, managed both actively and through passive index approaches.	Domestic and international equities such as common stocks, American depositary receipts, and real estate investment trusts that trade on public exchanges are classified as Level 1 investments and are valued at the closing price in the active market. Equity funds with unpublished prices are valued as Level 2 when the underlying holdings are comprised of Level 1 or Level 2 equity securities.
Fixed income: A mix of domestic and international bonds.	Investments in fixed income securities are generally classified as Level 2 investments and are valued based on prices reported in the market place. Additionally, the value of fixed income securities takes into consideration certain items such as broker quotes, spreads, yield curves, interest rates, and discount rates that apply to the term of a specific instrument.
Trust-owned life insurance (TOLI): Investments of taxable trusts aimed at minimizing the impact of taxes on the portfolio.	Investments in TOLI policies are classified as Level 2 investments and are valued based on the underlying investments held in the policy's separate accounts. The underlying assets are equity and fixed income pooled funds that are comprised of Level 1 and Level 2 securities.
Special situations: Investments in opportunistic strategies with the objective of diversifying and enhancing returns and exploiting short-term inefficiencies, as well as investments in promising new strategies of a longer-term nature. **Real estate:** Investments in traditional private market, equity-oriented investments in real properties (indirectly through pooled funds or partnerships) and in publicly traded real estate securities. **Private equity:** Investments in private partnerships that invest in private or public securities typically through privately-negotiated and/or structured transactions, including leveraged buyouts, venture capital, and distressed debt.	Investments in real estate, private equity, and special situations are generally classified as Net Asset Value as a Practical Expedient, since the underlying assets typically do not have publicly available observable inputs. The fund manager values the assets using various inputs and techniques depending on the nature of the underlying investments. Techniques may include purchase multiples for comparable transactions, comparable public company trading multiples, discounted cash flow analysis, prevailing market capitalization rates, recent sales of comparable investments, and independent third-party appraisals. The fair value of partnerships is determined by aggregating the value of the underlying assets less liabilities.

COMBINED NOTES TO FINANCIAL STATEMENTS (continued)
Southern Company and Subsidiary Companies 2018 Annual Report

The fair values, and actual allocations relative to the target allocations, of the Southern Company system's pension plans at December 31, 2018 and 2017 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. The registrants did not have any investments classified as Level 3 at December 31, 2018 or 2017.

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					
At December 31, 2018:	**Quoted Prices in Active Markets for Identical Assets (Level 1)**	**Significant Other Observable Inputs (Level 2)**	**Net Asset Value as a Practical Expedient (NAV)**	**Total**	**Target Allocation**	**Actual Allocation**
	(in millions)					
Southern Company						
Assets:						
Domestic equity[*]	$ 2,102	$ 1,030	$ —	$ 3,132	26%	28%
International equity[*]	1,344	1,325	—	2,669	25	25
Fixed income:					23	24
U.S. Treasury, government, and agency bonds	—	930	—	930		
Mortgage- and asset-backed securities	—	7	—	7		
Corporate bonds	—	1,195	—	1,195		
Pooled funds	—	654	—	654		
Cash equivalents and other	270	2	—	272		
Real estate investments	419	—	1,361	1,780	14	15
Special situations	—	—	171	171	3	1
Private equity	—	—	821	821	9	7
Total	$ 4,135	$ 5,143	$ 2,353	$ 11,631	100%	100%
Alabama Power						
Assets:						
Domestic equity[*]	$ 466	$ 228	$ —	$ 694	26%	28%
International equity[*]	298	293	—	591	25	25
Fixed income:					23	24
U.S. Treasury, government, and agency bonds	—	206	—	206		
Mortgage- and asset-backed securities	—	2	—	2		
Corporate bonds	—	265	—	265		
Pooled funds	—	145	—	145		
Cash equivalents and other	60	1	—	61		
Real estate investments	93	—	302	395	14	15
Special situations	—	—	38	38	3	1
Private equity	—	—	182	182	9	7
Total	$ 917	$ 1,140	$ 522	$ 2,579	100%	100%

At December 31, 2018:	Fair Value Measurements Using: Quoted Prices in Active Markets for Identical Assets (Level 1)	Significant Other Observable Inputs (Level 2)	Net Asset Value as a Practical Expedient (NAV)	Total	Target Allocation	Actual Allocation
		(in millions)				
Georgia Power						
Assets:						
Domestic equity[*]	$ 663	$ 325	$ —	$ 988	26%	28%
International equity[*]	424	418	—	842	25	25
Fixed income:					23	24
U.S. Treasury, government, and agency bonds	—	294	—	294		
Mortgage- and asset-backed securities	—	2	—	2		
Corporate bonds	—	377	—	377		
Pooled funds	—	206	—	206		
Cash equivalents and other	85	1	—	86		
Real estate investments	132	—	429	561	14	15
Special situations	—	—	54	54	3	1
Private equity	—	—	259	259	9	7
Total	$ 1,304	$ 1,623	$ 742	$ 3,669	100%	100%
Mississippi Power						
Assets:						
Domestic equity[*]	$ 91	$ 45	$ —	$ 136	26%	28%
International equity[*]	59	59	—	118	25	25
Fixed income:					23	24
U.S. Treasury, government, and agency bonds	—	40	—	40		
Corporate bonds	—	52	—	52		
Pooled funds	—	28	—	28		
Cash equivalents and other	12	—	—	12		
Real estate investments	18	—	59	77	14	15
Special situations	—	—	7	7	3	1
Private equity	—	—	36	36	9	7
Total	$ 180	$ 224	$ 102	$ 506	100%	100%

COMBINED NOTES TO FINANCIAL STATEMENTS (continued)
Southern Company and Subsidiary Companies 2018 Annual Report

At December 31, 2018:	Fair Value Measurements Using: Quoted Prices in Active Markets for Identical Assets (Level 1)	Significant Other Observable Inputs (Level 2)	Net Asset Value as a Practical Expedient (NAV)	Total	Target Allocation	Actual Allocation
		(in millions)				
Southern Power						
Assets:						
Domestic equity(*)	$ 22	$ 11	$ —	$ 33	26%	28%
International equity(*)	14	14	—	28	25	25
Fixed income:					23	24
U.S. Treasury, government, and agency bonds	—	10	—	10		
Corporate bonds	—	13	—	13		
Pooled funds	—	7	—	7		
Cash equivalents and other	3	—	—	3		
Real estate investments	4	—	15	19	14	15
Special situations	—	—	2	2	3	1
Private equity	—	—	9	9	9	7
Total	$ 43	$ 55	$ 26	$ 124	100%	100%
Southern Company Gas						
Assets:						
Domestic equity(*)	$ 145	$ 71	$ —	$ 216	26%	28%
International equity(*)	92	91	—	183	25	25
Fixed income:					23	24
U.S. Treasury, government, and agency bonds	—	64	—	64		
Corporate bonds	—	82	—	82		
Pooled funds	—	45	—	45		
Cash equivalents and other	19	—	—	19		
Real estate investments	29	—	94	123	14	15
Special situations	—	—	12	12	3	1
Private equity	—	—	56	56	9	7
Total	$ 285	$ 353	$ 162	$ 800	100%	100%

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

	Fair Value Measurements Using					
At December 31, 2017:	Quoted Prices in Active Markets for Identical Assets (Level 1)	Significant Other Observable Inputs (Level 2)	Net Asset Value as a Practical Expedient (NAV)	Total	Target Allocation	Actual Allocation
			(in millions)			
Southern Company[a]						
Assets:						
Domestic equity[b]	$ 2,559	$ 1,482	$ —	$ 4,041	26%	31%
International equity[b]	1,555	1,569	—	3,124	25	25
Fixed income:					23	24
U.S. Treasury, government, and agency bonds	—	926	—	926		
Mortgage- and asset-backed securities	—	8	—	8		
Corporate bonds	—	1,241	—	1,241		
Pooled funds	—	650	—	650		
Cash equivalents and other	301	36	48	385		
Real estate investments	472	—	1,204	1,676	14	13
Special situations	—	—	180	180	3	1
Private equity	—	—	670	670	9	6
Total	$ 4,887	$ 5,912	$ 2,102	$ 12,901	100%	100%
Alabama Power						
Assets:						
Domestic equity[b]	$ 572	$ 276	$ —	$ 848	26%	31%
International equity[b]	370	333	—	703	25	25
Fixed income:					23	24
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	14	13
Special situations	—	—	43	43	3	1
Private equity	—	—	159	159	9	6
Total	$ 1,104	$ 1,255	$ 485	$ 2,844	100%	100%

	Fair Value Measurements Using					
At December 31, 2017:	Quoted Prices in Active Markets for Identical Assets (Level 1)	Significant Other Observable Inputs (Level 2)	Net Asset Value as a Practical Expedient (NAV)	Total	Target Allocation	Actual Allocation
			(in millions)			
Georgia Power						
Assets:						
Domestic equity[(b)]	$ 819	$ 394	$ —	$ 1,213	26%	31%
International equity[(b)]	529	477	—	1,006	25	25
Fixed income:					23	24
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	14	13
Special situations	—	—	61	61	3	1
Private equity	—	—	228	228	9	6
Total	$ 1,582	$ 1,794	$ 693	$ 4,069	100%	100%
Mississippi Power						
Assets:						
Domestic equity[(b)]	$ 113	$ 55	$ —	$ 168	26%	31%
International equity[(b)]	73	66	—	139	25	25
Fixed income:					23	24
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	14	13
Special situations	—	—	9	9	3	1
Private equity	—	—	32	32	9	6
Total	$ 218	$ 249	$ 97	$ 564	100%	100%

	Fair Value Measurements Using					
At December 31, 2017:	Quoted Prices in Active Markets for Identical Assets (Level 1)	Significant Other Observable Inputs (Level 2)	Net Asset Value as a Practical Expedient (NAV)	Total	Target Allocation	Actual Allocation
		(in millions)				
Southern Power						
Assets:						
Domestic equity[(b)]	$ 28	$ 13	$ —	$ 41	26%	31%
International equity[(b)]	18	16	—	34	25	25
Fixed income:					23	24
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	14	13
Special situations	—	—	2	2	3	1
Private equity	—	—	8	8	9	6
Total	$ 53	$ 61	$ 24	$ 138	100%	100%

(a) Target and actual allocations reflect the asset allocations for only the Southern Company system pension plan prior to its merger with the Southern Company Gas pension plan on January 1, 2018.

(b) 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 are presented below. The fair value measurements exclude cash, receivables related to investment income, pending investment sales, and payables related to pending investment purchases. Special situations (absolute return and hedge funds) investment assets are presented in the tables below based on the nature of the investment.

	Fair Value Measurements Using			
At December 31, 2017:	Quoted Prices in Active Markets for Identical Assets (Level 1)	Significant Other Observable Inputs (Level 2)	Net Asset Value as a Practical Expedient (NAV)	Total
		(in millions)		
Southern Company Gas				
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.

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

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

The fair values of the applicable registrants' other postretirement benefit plan assets at December 31, 2018 and 2017 are presented below. The registrants did not have any investments classified as Level 3 at December 31, 2018 or 2017. 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					
At December 31, 2018:	Quoted Prices in Active Markets for Identical Assets (Level 1)	Significant Other Observable Inputs (Level 2)	Net Asset Value as a Practical Expedient (NAV)	Total	Target Allocation	Actual Allocation
			(in millions)			
Southern Company						
Assets:						
Domestic equity[(*)]	$ 100	$ 76	$ —	$ 176	39%	40%
International equity[(*)]	45	75	—	120	23	22
Fixed income:					29	30
U.S. Treasury, government, and agency bonds	—	34	—	34		
Corporate bonds	—	35	—	35		
Pooled funds	—	81	—	81		
Cash equivalents and other	13	—	—	13		
Trust-owned life insurance	—	386	—	386		
Real estate investments	13	—	40	53	5	5
Special situations	—	—	4	4	1	—
Private equity	—	—	24	24	3	3
Total	$ 171	$ 687	$ 68	$ 926	100%	100%
Alabama Power						
Assets:						
Domestic equity[(*)]	$ 35	$ 10	$ —	$ 45	43%	45%
International equity[(*)]	12	12	—	24	21	21
Fixed income:					28	28
U.S. Treasury, government, and agency bonds	—	10	—	10		
Corporate bonds	—	11	—	11		
Pooled funds	—	6	—	6		
Cash equivalents and other	3	—	—	3		
Trust-owned life insurance	—	233	—	233		
Real estate investments	4	—	13	17	4	4
Special situations	—	—	2	2	1	—
Private equity	—	—	8	8	3	2
Total	$ 54	$ 282	$ 23	$ 359	100%	100%

At December 31, 2018:	Fair Value Measurements Using: Quoted Prices in Active Markets for Identical Assets (Level 1)	Significant Other Observable Inputs (Level 2)	Net Asset Value as a Practical Expedient (NAV)	Total	Target Allocation	Actual Allocation
		(in millions)				
Georgia Power						
Assets:						
Domestic equity[*]	$ 41	$ 9	$ —	$ 50	36%	35%
International equity[*]	17	32	—	49	24	24
Fixed income:					33	35
U.S. Treasury, government, and agency bonds	—	7	—	7		
Corporate bonds	—	10	—	10		
Pooled funds	—	44	—	44		
Cash equivalents and other	5	—	—	5		
Trust-owned life insurance	—	153	—	153		
Real estate investments	4	—	11	15	4	4
Special situations	—	—	2	2	1	—
Private equity	—	—	7	7	2	2
Total	$ 67	$ 255	$ 20	$ 342	100%	100%
Mississippi Power						
Assets:						
Domestic equity[*]	$ 3	$ 2	$ —	$ 5	21%	22%
International equity[*]	2	2	—	4	20	20
Fixed income:					38	39
U.S. Treasury, government, and agency bonds	—	6	—	6		
Corporate bonds	—	2	—	2		
Pooled funds	—	1	—	1		
Cash equivalents and other	1	—	—	1		
Real estate investments	1	—	2	3	11	12
Special situations	—	—	—	—	3	1
Private equity	—	—	1	1	7	6
Total	$ 7	$ 13	$ 3	$ 23	100%	100%

At December 31, 2018:	Fair Value Measurements Using: Quoted Prices in Active Markets for Identical Assets (Level 1)	Significant Other Observable Inputs (Level 2)	Net Asset Value as a Practical Expedient (NAV)	Total	Target Allocation	Actual Allocation
		(in millions)				
Southern Company Gas						
Assets:						
Domestic equity(*)	$ 2	$ 47	$ —	$ 49	51%	51%
International equity(*)	1	17	—	18	20	18
Fixed income:					25	28
U.S. Treasury, government, and agency bonds	—	1	—	1		
Corporate bonds	—	1	—	1		
Pooled funds	—	24	—	24		
Cash equivalents and other	1	—	—	1		
Real estate investments	—	—	1	1	2	2
Special situations	—	—	—	—	1	—
Private equity	—	—	1	1	1	1
Total	$ 4	$ 90	$ 2	$ 96	100%	100%

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

At December 31, 2017:	Fair Value Measurements Using: Quoted Prices in Active Markets for Identical Assets (Level 1)	Significant Other Observable Inputs (Level 2)	Net Asset Value as a Practical Expedient (NAV)	Total	Target Allocation	Actual Allocation
			(in millions)			
Southern Company[a]						
Assets:						
Domestic equity[b]	$ 135	$ 104	$ —	$ 239	37%	40%
International equity[b]	47	98	—	145	23	23
Fixed income:					30	29
U.S. Treasury, government, and agency bonds	—	32	—	32		
Corporate bonds	—	37	—	37		
Pooled funds	—	79	—	79		
Cash equivalents and other	12	—	1	13		
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	$ 210	$ 776	$ 62	$ 1,048	100%	100%
Alabama Power						
Assets:						
Domestic equity[b]	$ 52	$ 12	$ —	$ 64	42%	44%
International equity[b]	16	14	—	30	22	22
Fixed income:					28	28
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	4	4
Special situations	—	—	2	2	1	—
Private equity	—	—	7	7	3	2
Total	$ 75	$ 309	$ 21	$ 405	100%	100%

At December 31, 2017:	Fair Value Measurements Using: Quoted Prices in Active Markets for Identical Assets (Level 1)	Significant Other Observable Inputs (Level 2)	Net Asset Value as a Practical Expedient (NAV)	Total	Target Allocation	Actual Allocation
		(in millions)				
Georgia Power						
Assets:						
Domestic equity[(b)]	$ 53	$ 11	$ —	$ 64	36%	38%
International equity[(b)]	14	46	—	60	24	24
Fixed income:					33	31
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	4	4
Special situations	—	—	2	2	1	1
Private equity	—	—	6	6	2	2
Total	$ 77	$ 288	$ 19	$ 384	100%	100%
Mississippi Power						
Assets:						
Domestic equity[(b)]	$ 4	$ 2	$ —	$ 6	21%	25%
International equity[(b)]	3	2	—	5	21	20
Fixed income:					37	38
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	12	11
Special situations	—	—	—	—	2	1
Private equity	—	—	1	1	7	5
Total	$ 9	$ 12	$ 3	$ 24	100%	100%

(a) Target and actual allocations reflect the asset allocations for only the Southern Company other postretirement benefit plans prior to the merger of the plans with the Southern Company Gas other postretirement benefit plans on January 1, 2018.

(b) 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 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			
At December 31, 2017:	Quoted Prices in Active Markets for Identical Assets (Level 1)	Significant Other Observable Inputs (Level 2)	Net Asset Value as a Practical Expedient (NAV)	Total
		(in millions)		
Southern Company Gas				
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.

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

	Target	2017
Other postretirement benefit plan assets:		
Equity	72%	76%
Fixed Income	24	20
Cash	1	2
Other	3	2
Total	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 2018, 2017, and 2016 were as follows:

	Southern Company	Alabama Power	Georgia Power	Mississippi Power	Southern Power
			(in millions)		
2018	$ 119	$ 24	$ 26	$ 5	$ 3
2017	118	23	26	5	N/A
2016	105	23	27	5	N/A

	Southern Company Gas
	(in millions)
Successor – 2018	$ 18
Successor – 2017	19
Successor – July 1, 2016 through December 31, 2016	8
Predecessor – January 1, 2016 through June 30, 2016	12

12. STOCK COMPENSATION

Stock-Based Compensation

Stock-based compensation primarily in the form of Southern Company performance share units (PSU) and restricted stock units (RSU) may be granted through the Omnibus Incentive Compensation Plan to a large segment of Southern Company system employees ranging from line management to executives. Southern Company Gas and Southern Power had no employee participants in the stock-based compensation plans until 2017 and 2018, respectively. In conjunction with the Merger, stock-based compensation in the form of Southern Company RSUs and PSUs was granted to certain executives of Southern Company Gas through the Southern Company Omnibus Incentive Compensation Plan.

At December 31, 2018, the number of current and former employees participating in stock-based compensation programs for the registrants was as follows:

	Southern Company	Alabama Power	Georgia Power	Mississippi Power	Southern Power	Southern Company Gas
Number of employees	4,716	745	822	164	95	285

Employees become immediately vested in PSUs and RSUs 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. In addition, the registrants recognize forfeitures as they occur.

All unvested PSUs and RSUs vest immediately upon a change in control where Southern Company is not the surviving corporation.

Performance Share Units

PSUs granted to employees vest at the end of a three-year performance period. 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 PSUs granted, based on achievement of the performance goals established by the Compensation Committee of the Southern Company Board of Directors.

Southern Company has issued three types of PSUs, each with a unique performance goal. These types of PSUs include total shareholder return (TSR) awards based on the TSR for Southern Company common stock during the three-year performance period as compared to a group of industry peers; ROE awards based on Southern Company's equity-weighted return over the performance period; and EPS awards based on Southern Company's cumulative EPS over the performance period. EPS awards were not granted in 2018.

The fair value of TSR 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 industry peers over the performance period. In determining the fair value of the TSR 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 TSR awards granted:

Year Ended December 31	**2018**	2017	2016
Expected volatility	**14.9%**	15.6%	15.0%
Expected term *(in years)*	**3**	3	3
Interest rate	**2.4%**	1.4%	0.8%
Weighted average grant-date fair value	**$43.75**	$49.08	$45.06

The registrants recognize TSR award compensation expense on a straight-line basis over the three-year performance period without remeasurement.

The fair values of EPS awards and ROE awards are based on the closing stock price of Southern Company common stock on the date of the grant. The weighted average grant-date fair value of the awards granted during 2018, 2017, and 2016 was $43.49, $49.21, and $48.87, respectively. Compensation expense for EPS and ROE awards is generally recognized ratably over the three-year performance period adjusted for expected changes in EPS and ROE performance. Total compensation cost recognized for vested EPS awards and ROE awards reflects final performance metrics.

Southern Company's total unvested PSUs outstanding at December 31, 2017 was 2.9 million. In February 2018, 1.5 million PSUs vested for the three-year performance period ended December 31, 2017 were converted into 1.9 million shares outstanding at a share price of $44.68.

During 2018, Southern Company granted 1.3 million PSUs and 1.9 million PSUs were vested or forfeited, resulting in 2.5 million unvested PSUs outstanding at December 31, 2018. In February 2019, the PSUs that vested for the three-year performance period ended December 31, 2018 were converted into 1.7 million shares outstanding at a share price of $49.24.

Total PSU compensation cost, and the related tax benefit recognized in income, for the years ended December 31, 2018, 2017, and 2016 are as follows:

	2018	2017	2016
		(in millions)	
Southern Company			
Compensation cost recognized in income	**$ 91**	$ 74	$ 96
Tax benefit of compensation cost recognized in income	**24**	29	37
Alabama Power			
Compensation cost recognized in income	**$ 11**	$ 9	$ 15
Tax benefit of compensation cost recognized in income	**3**	4	6
Georgia Power			
Compensation cost recognized in income	**$ 11**	$ 10	$ 15
Tax benefit of compensation cost recognized in income	**3**	4	6
Mississippi Power			
Compensation cost recognized in income	**$ 3**	$ 2	$ 4
Tax benefit of compensation cost recognized in income	**1**	1	1
Southern Power			
Compensation cost recognized in income	**$ 4**	N/A	N/A
Tax benefit of compensation cost recognized in income	**1**	N/A	N/A
Southern Company Gas			
Compensation cost recognized in income	**$ 11**	$ 8	N/A
Tax benefit of compensation cost recognized in income	**3**	3	N/A

The compensation cost related to the grant of Southern Company PSUs to the employees of the traditional electric operating companies, Southern Power, and Southern Company Gas is recognized in each respective registrant's financial statements with a corresponding credit to equity representing a capital contribution from Southern Company.

At December 31, 2018, Southern Company's total unrecognized compensation cost related to PSUs was $30 million and is expected to be recognized over a weighted-average period of approximately 16 months. The total unrecognized compensation cost related to PSUs as of December 31, 2018 was immaterial for all other registrants.

Restricted Stock Units

Beginning in 2017, employees are granted RSUs in addition to PSUs. One-third of the RSUs granted to employees vest each year throughout a three-year service period. Shares of Southern Company common stock are delivered to employees at the end of each vesting period.

The fair value of RSUs is based on the closing stock price of Southern Company common stock on the date of the grant. The weighted average grant-date fair values of RSUs granted during 2018 and 2017 were $43.81 and $49.25, respectively. Since one-third of the RSUs vest each year throughout a three-year service period, compensation cost for RSUs is generally recognized over the corresponding one-, two-, or three-year vesting period.

Southern Company had 0.7 million RSUs outstanding at December 31, 2017. During 2018, Southern Company granted 0.7 million RSUs and 0.3 million RSUs were vested or forfeited, resulting in 1.1 million unvested RSUs outstanding at December 31, 2018, including RSUs related to employee retention agreements.

For the years ended December 31, 2018 and 2017, Southern Company's total compensation cost for RSUs recognized in income was $27 million and $25 million, respectively. The related tax benefit also recognized in income was $7 million and $10 million for the years ended December 31, 2018 and 2017, respectively. Total unrecognized compensation cost related to RSUs as of December 31, 2018 for Southern Company of $13 million will be recognized over a weighted-average period of approximately 16 months.

Total RSUs outstanding and total compensation cost and related tax benefit for the RSUs recognized in income for the years ended December 31, 2018 and 2017, as well as the total unrecognized compensation cost as of December 31, 2018, were immaterial for all other registrants.

Stock Options

In 2015, Southern Company discontinued granting 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. As of December 31, 2018, the weighted average remaining contractual term for the options outstanding and exercisable was approximately 4 years.

As of December 31, 2017, all stock option awards are vested and compensation cost fully recognized. Total compensation cost for stock option awards and the related tax benefits recognized in income for the years ended December 31, 2017 and 2016 were immaterial for Southern Company, Alabama Power, Georgia Power, and Mississippi Power.

Southern Company's activity in the stock option program for 2018 is summarized below:

	Shares Subject to Option	Weighted Average Exercise Price
	(in millions)	
Outstanding at December 31, 2017	18.6	$ 41.68
Exercised	1.1	37.82
Outstanding and Exercisable at December 31, 2018	**17.5**	**$ 41.92**

Southern Company's cash receipts from issuances related to stock options exercised under the share-based payment arrangements for the years ended December 31, 2018, 2017, and 2016 were $41 million, $239 million, and $448 million, respectively.

At December 31, 2018, the aggregate intrinsic value for the options outstanding and exercisable was as follows:

	Southern Company	Alabama Power	Georgia Power	Mississippi Power
		(in millions)		
Total intrinsic value for outstanding and exercisable options	$ 39	$ 5	$ 13	$ 1

Total intrinsic value of options exercised, and the related tax benefit, for the years ended December 31, 2018, 2017, and 2016 are presented below:

Year Ended December 31	2018	2017	2016
		(in millions)	
Southern Company			
Intrinsic value of options exercised	**$ 9**	$ 64	$ 120
Tax benefit of options exercised	**2**	25	46
Alabama Power			
Intrinsic value of options exercised	**$ 2**	$ 12	$ 21
Tax benefit of options exercised	**—**	5	8
Georgia Power			
Intrinsic value of options exercised	**$ 2**	$ 13	$ 18
Tax benefit of options exercised	**—**	5	7
Mississippi Power			
Intrinsic value of options exercised	**$ 1**	$ 2	$ 4
Tax benefit of options exercised	**—**	1	2

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 RSUs, 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 Southern Company Gas PSU was converted into an award of Southern Company RSUs. 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.

Southern Company Restricted Stock Awards

At the effective time of the Merger, each outstanding award of existing Southern Company Gas PSUs was converted into an award of Southern Company RSUs. 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 RSUs with a grant-date fair value of $53.83, based on the closing stock price of Southern Company common stock on the date of the grant. As a portion of the fair value of the award related to pre-combination service, the grant date fair value was allocated to pre- or post-combination service and accounted for as Merger consideration or compensation cost, respectively. Approximately $13 million of the grant date fair value was allocated to Merger consideration. Southern Company Gas recognized the remaining fair value as compensation expense on a straight-line basis over the remaining vesting period. As of December 31, 2018, all RSUs are vested and compensation cost is fully recognized.

For the years ended December 31, 2018, 2017, and 2016, total compensation cost for RSUs recognized in income was $2 million, $8 million, and $13 million, respectively, with the related tax benefit of $1 million, $4 million, and $4 million, respectively, also recognized in income. The compensation cost related to the grant of RSUs to Southern Company Gas employees is recognized in Southern Company Gas' financial statements with a corresponding credit to equity, representing a capital contribution from Southern Company.

Southern Company Gas Change in Control Awards

Southern Company awarded PSUs 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 compensation cost of the change in control benefit is recognized in Southern Company Gas' financial statements with a corresponding credit to a liability. 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 compensation cost of the achievement shares is recognized in Southern Company Gas' financial statements with a corresponding credit to equity, representing a capital contribution from Southern Company. The expected payout is reevaluated annually with expense recognized to date increased or decreased proportionately based on the expected performance. The compensation cost ultimately recognized for the achievement shares will be based on the actual performance.

For the years ended December 31, 2018, 2017, and 2016, total compensation cost for the change in control awards recognized in income was $5 million, $12 million, and $4 million, respectively, with the related tax benefit of $2 million, $6 million, and less than $1 million, respectively, also recognized in income. As of December 31, 2018, $2 million of total unrecognized compensation cost related to change in control awards will be recognized over a weighted-average period of approximately six months.

Predecessor

For the predecessor period of January 1, 2016 through June 30, 2016, 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, RSUs, 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 period, Southern Company Gas recognized stock-based compensation cost 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.

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. Southern Company Gas estimated forfeitures over the requisite service period when recognizing compensation cost. These estimates were adjusted to the extent that actual forfeitures differ, or were expected to materially differ, from such estimates. The difference between the proceeds from the exercise of Southern Company Gas' 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 period of January 1, 2016 through June 30, 2016, total compensation cost for cash and stock-based awards recognized in income was $24 million with related tax benefits of an immaterial amount also recognized in income.

13. 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 each registrant of what a market participant would use in pricing an asset or liability. If there is little available market data, then each registrant'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.

At December 31, 2018, 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				
At December 31, 2018:	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)		
Southern Company					
Assets:					
Energy-related derivatives[a][b]	$ 469	$ 292	$ —	$ —	$ 761
Foreign currency derivatives	—	75	—	—	75
Investments in trusts:[c][d]					
Domestic equity	601	107	—	—	708
Foreign equity	53	173	—	—	226
U.S. Treasury and government agency securities	—	261	—	—	261
Municipal bonds	—	83	—	—	83
Pooled funds – fixed income	—	14	—	—	14
Corporate bonds	24	290	—	—	314
Mortgage and asset backed securities	—	68	—	—	68
Private equity	—	—	—	45	45
Cash and cash equivalents	16	—	—	—	16
Other	34	4	—	—	38
Cash equivalents	765	1	—	—	766
Other investments	—	12	—	—	12
Total	$ 1,962	$ 1,380	$ —	$ 45	$ 3,387
Liabilities:					
Energy-related derivatives[a][b]	$ 648	$ 316	$ —	$ —	$ 964
Interest rate derivatives	—	49	—	—	49
Foreign currency derivatives	—	23	—	—	23
Contingent consideration	—	—	21	—	21
Total	$ 648	$ 388	$ 21	$ —	$ 1,057

At December 31, 2018:	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)		
Alabama Power					
Assets:					
Energy-related derivatives	$ —	$ 6	$ —	$ —	$ 6
Nuclear decommissioning trusts:[c]					
Domestic equity	396	95	—	—	491
Foreign equity	53	50	—	—	103
U.S. Treasury and government agency securities	—	18	—	—	18
Municipal bonds	—	1	—	—	1
Corporate bonds	24	135	—	—	159
Mortgage and asset backed securities	—	23	—	—	23
Private equity	—	—	—	45	45
Other	6	—	—	—	6
Cash equivalents	116	1	—	—	117
Other investments	—	12	—	—	12
Total	$ 595	$ 341	$ —	$ 45	$ 981
Liabilities:					
Energy-related derivatives	$ —	$ 10	$ —	$ —	$ 10
Georgia Power					
Assets:					
Energy-related derivatives	$ —	$ 6	$ —	$ —	$ 6
Nuclear decommissioning trusts:[c][d]					
Domestic equity	205	1	—	—	206
Foreign equity	—	119	—	—	119
U.S. Treasury and government agency securities	—	243	—	—	243
Municipal bonds	—	82	—	—	82
Corporate bonds	—	155	—	—	155
Mortgage and asset backed securities	—	45	—	—	45
Other	19	4	—	—	23
Total	$ 224	$ 655	$ —	$ —	$ 879
Liabilities:					
Energy-related derivatives	$ —	$ 21	$ —	$ —	$ 21
Interest rate derivatives	—	2	—	—	2
Total	$ —	$ 23	$ —	$ —	$ 23

COMBINED NOTES TO FINANCIAL STATEMENTS (continued)
Southern Company and Subsidiary Companies 2018 Annual Report

At December 31, 2018:	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)		
Mississippi Power					
Assets:					
Energy-related derivatives	$ —	$ 3	$ —	$ —	$ 3
Cash equivalents	255	—	—	—	255
Total	$ 255	$ 3	$ —	$ —	$ 258
Liabilities:					
Energy-related derivatives	$ —	$ 9	$ —	$ —	$ 9
Southern Power					
Assets:					
Energy-related derivatives	$ —	$ 4	$ —	$ —	$ 4
Foreign currency derivatives	—	75	—	—	75
Cash equivalents	46	—	—	—	46
Total	$ 46	$ 79	$ —	$ —	$ 125
Liabilities:					
Energy-related derivatives	$ —	$ 8	$ —	$ —	$ 8
Foreign currency derivatives	—	23	—	—	23
Contingent consideration	—	—	21	—	21
Total	$ —	$ 31	$ 21	$ —	$ 52
Southern Company Gas					
Assets:					
Energy-related derivatives[a][b]	$ 469	$ 272	$ —	$ —	$ 741
Non-qualified deferred compensation trusts:					
Domestic equity	—	11	—	—	11
Foreign equity	—	4	—	—	4
Pooled funds - fixed income	—	14	—	—	14
Cash equivalents	4	—	—	—	4
Cash equivalents	40	—	—	—	40
Total	$ 513	$ 301	$ —	$ —	$ 814
Liabilities:					
Energy-related derivatives[a][b]	$ 648	$ 261	$ —	$ —	$ 909

(a) Energy-related derivatives exclude $8 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 $277 million.

(c) Excludes receivables related to investment income, pending investment sales, payables related to pending investment purchases, and currencies. See Note 6 under "Nuclear Decommissioning" for additional information.

(d) Includes investment securities pledged to creditors and collateral received and excludes payables related to the securities lending program. See Note 6 under "Nuclear Decommissioning" for additional information.

At 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				
At 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)		
Southern Company					
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

At 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)		
Alabama Power					
Assets:					
Energy-related derivatives	$ —	$ 4	$ —	$ —	$ 4
Nuclear decommissioning trusts:[(d)]					
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
Georgia Power					
Assets:					
Energy-related derivatives	$ —	$ 6	$ —	$ —	$ 6
Nuclear decommissioning trusts:[(d)(e)]					
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

At 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)		
Mississippi Power					
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
Southern Power					
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
Southern Company Gas					
Assets:					
Energy-related derivatives[(a)(b)]	$ 331	$ 223	$ —	$ —	$ 554
Liabilities:					
Energy-related derivatives[(a)(b)]	$ 479	$ 181	$ —	$ —	660

(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) For additional detail, see the nuclear decommissioning trusts sections for Alabama Power and Georgia Power in this table.

(d) Excludes receivables related to investment income, pending investment sales, payables related to pending investment purchases, and currencies. See Note 6 under "Nuclear Decommissioning" for additional information.

(e) Includes investment securities pledged to creditors and collateral received and excludes payables related to the securities lending program. See Note 6 under "Nuclear Decommissioning" for additional information.

Valuation Methodologies

The energy-related derivatives primarily consist of exchange-traded and over-the-counter financial products for natural gas and physical power products, including, from time to time, basis swaps. These are standard products used within the energy industry and are valued using the market approach. The inputs used are mainly from observable market sources, such as forward natural gas prices, power prices, implied volatility, and overnight index swap interest rates. Interest rate derivatives are also standard over-the-counter products that are valued using observable market data and assumptions commonly used by market participants. The fair value of interest rate derivatives reflects the net present value of expected payments and receipts under the swap

agreement based on the market's expectation of future interest rates. Additional inputs to the net present value calculation may include the contract terms, counterparty credit risk, and occasionally, implied volatility of interest rate options. The fair value of cross-currency swaps reflects the net present value of expected payments and receipts under the swap agreement based on the market's expectation of future foreign currency exchange rates. Additional inputs to the net present value calculation may include the contract terms, counterparty credit risk, and discount rates. The interest rate derivatives and cross-currency swaps are categorized as Level 2 under Fair Value Measurements as these inputs are based on observable data and valuations of similar instruments. See Note 14 for additional information on how these derivatives are used.

For fair value measurements of the investments within the nuclear decommissioning trusts and the non-qualified deferred compensation 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.

The NRC requires licensees of commissioned nuclear power reactors to establish a plan for providing reasonable assurance of funds for future decommissioning. See Note 6 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, which commenced at the commercial operation of the respective facility and continue 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. 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 categorized as Level 3 under Fair Value Measurements 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.

The fair value measurements of private equity investments held in Alabama Power's nuclear decommissioning trusts that are calculated at net asset value per share (or its equivalent) as a practical expedient totaled $45 million and $29 million at December 31, 2018 and 2017, respectively. Unfunded commitments related to the private equity investments totaled $50 million and $21 million at December 31, 2018 and 2017, respectively. Private equity funds include funds-of-funds that invest 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.

At December 31, 2018 and 2017, other financial instruments for which the carrying amount did not equal fair value were as follows:

	Southern Company[a][b]	Alabama Power	Georgia Power	Mississippi Power	Southern Power	Southern Company Gas[b]
			(in millions)			
At December 31, 2018:						
Long-term debt, including securities due within one year:						
Carrying amount	**$ 45,023**	**$ 8,120**	**$ 9,838**	**$ 1,579**	**$ 5,017**	**$ 5,940**
Fair value	**44,824**	**8,370**	**9,800**	**1,546**	**4,980**	**5,965**
At December 31, 2017:						
Long-term debt, including securities due within one year:						
Carrying amount	$ 48,151	$ 7,625	$ 11,777	$ 2,086	$ 5,841	$ 6,048
Fair value	51,348	8,305	12,531	2,076	6,079	6,471

(a) Includes long-term debt of Gulf Power, which is classified as liabilities held for sale on Southern Company's balance sheet at December 31, 2018. See Note 15 under "Southern Company's Sale of Gulf Power" and "Assets Held for Sale" for additional information.
(b) The long-term debt of Southern Company Gas is recorded at amortized cost, including the fair value adjustments at the effective date of the Merger. Southern Company Gas amortizes the fair value adjustments over the lives of the respective bonds.

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 registrants.

14. DERIVATIVES

Southern Company, the traditional electric operating companies, Southern Power, and Southern Company Gas are exposed to market risks, including commodity price risk, interest rate risk, weather risk, and occasionally foreign currency exchange rate risk. To manage the volatility attributable to these exposures, each company nets its exposures, where possible, to take advantage of natural offsets and enters into various derivative transactions for the remaining exposures pursuant to each company's policies in areas such as counterparty exposure and risk management practices. Southern Company Gas' wholesale gas operations use various contracts in its commercial activities that generally meet the definition of derivatives. For the traditional electric operating companies, Southern Power, and Southern Company Gas' other businesses, each company's policy is that derivatives are to be used primarily for hedging purposes and mandates strict adherence to all applicable risk management policies. Derivative positions are monitored using techniques including, but not limited to, market valuation, value at risk, stress testing, and sensitivity analysis. Derivative instruments are recognized at fair value in the balance sheets as either assets or liabilities and are presented on a net basis. See Note 13 for additional fair value information. In the statements of cash flows, any cash impacts of settled energy-related and interest rate derivatives are recorded as operating activities. Any 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.

The registrants adopted ASU 2017-12 as of January 1, 2018. See Note 1 under "Recently Adopted Accounting Standards – Other" for additional information.

Energy-Related Derivatives

The traditional electric operating companies, Southern Power, and Southern Company Gas 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 the 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 of Southern Company Gas 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 are 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, be material and can adversely affect its results of operations.

Southern Company Gas also enters into weather derivative contracts as economic hedges of 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 operating revenues.

Energy-related derivative contracts are accounted for under one of three methods:

- *Regulatory Hedges* – Energy-related derivative contracts designated as regulatory hedges relate primarily to the traditional electric operating companies' and 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 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 AOCI before being recognized in the statements of income in the same period and in the same income statement line item as the earnings effect of the hedged transactions.
- *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, 2018, the net volume of energy-related derivative contracts for natural gas positions, together with the longest hedge date 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 for derivatives not designated as hedges, were as follows:

	Net Purchased mmBtu	Longest Hedge Date	Longest Non-Hedge Date
	(in millions)		
Southern Company(*)	431	2022	2029
Alabama Power	74	2022	—
Georgia Power	153	2022	—
Mississippi Power	63	2022	—
Southern Power	15	2020	—
Southern Company Gas(*)	120	2021	2029

(*) Southern Company Gas' derivative instruments include 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. Southern Company Gas' volume represents the net of long natural gas positions of 4,159 million mmBtu and short natural gas positions of 4,039 million mmBtu at December 31, 2018, which is also included in Southern Company's total volume.

At December 31, 2018, the net volume of Southern Power's energy-related derivative contracts for power to be sold was 2 million MWHs, all of which expire by 2020.

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 natural gas due to operational constraints. The maximum expected volume of natural gas subject to such a feature is 23 million mmBtu for Southern Company, which includes 4 million mmBtu for Alabama Power, 7 million mmBtu for Georgia Power, 3 million mmBtu for Mississippi Power, and 7 million mmBtu for Southern Power.

For cash flow hedges of energy-related derivatives, the estimated pre-tax gains (losses) expected to be reclassified from AOCI to earnings for the year ending December 31, 2019 are immaterial for all registrants.

Interest Rate Derivatives

Southern Company and certain subsidiaries may 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 derivatives' fair value gains or losses are recorded in OCI and are reclassified into earnings at the same time and presented on the same income statement line item as the earnings effect of the hedged transactions. 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 on the same income statement line item. 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, 2018, 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, 2018
	(in millions)				*(in millions)*
Fair Value Hedges of Existing Debt					
Southern Company(*)	$ 300	2.75%	3-month LIBOR + 0.92%	June 2020	$ (4)
Southern Company(*)	1,500	2.35%	1-month LIBOR + 0.87%	July 2021	(43)
Georgia Power	200	4.25%	3-month LIBOR + 2.46%	December 2019	(2)
Southern Company Consolidated	$ 2,000				$ (49)

(*) Represents the Southern Company parent entity.

The estimated pre-tax gains (losses) related to interest rate derivatives expected to be reclassified from AOCI to interest expense for the year ending December 31, 2019 are $(19) million for Southern Company and immaterial for all other registrants. Deferred gains and losses related to interest rate derivatives are expected to be amortized into earnings through 2046 for the Southern Company parent entity, 2035 for Alabama Power, 2037 for Georgia Power, 2028 for Mississippi Power, and 2046 for Southern Company Gas.

Foreign Currency Derivatives

Southern Company and certain subsidiaries, including Southern Power, may 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 derivatives' fair value gains or losses are recorded in OCI and are reclassified into earnings at the same time and on the same income statement line as the earnings effect of the hedged transactions, including foreign currency gains or losses arising from changes in the U.S. currency exchange rates. The derivatives employed as hedging instruments are structured to minimize ineffectiveness.

At December 31, 2018, 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, 2018
	(in millions)		*(in millions)*			*(in millions)*
Cash Flow Hedges of Existing Debt						
Southern Power	$ 677	2.95%	€ 600	1.00%	June 2022	$ 25
Southern Power	564	3.78%	500	1.85%	June 2026	27
Total	$ 1,241		€ 1,100			$ 52

The estimated pre-tax gains (losses) related to Southern Power's foreign currency derivatives that will be reclassified from AOCI to earnings for the year ending December 31, 2019 are $(23) million.

Derivative Financial Statement Presentation and Amounts

Southern Company, the traditional electric operating companies, Southern Power, and Southern Company Gas 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. The 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, 2018 and 2017, the fair value of energy-related derivatives, interest rate derivatives, and foreign currency derivatives was reflected in the balance sheets as follows:

	2018		2017	
Derivative Category and Balance Sheet Location	**Assets**	**Liabilities**	**Assets**	**Liabilities**
		(in millions)		
Southern Company				
Derivatives designated as hedging instruments for regulatory purposes				
Energy-related derivatives:				
Other current assets/Other current liabilities	**$ 8**	**$ 23**	$ 10	$ 43
Other deferred charges and assets/Other deferred credits and liabilities	**9**	**26**	7	24
Assets held for sale, current/Liabilities held for sale, current	**—**	**6**	—	—
Total derivatives designated as hedging instruments for regulatory purposes	**$ 17**	**$ 55**	$ 17	$ 67
Derivatives designated as hedging instruments in cash flow and fair value hedges				
Energy-related derivatives:				
Other current assets/Other current liabilities	**$ 3**	**$ 7**	$ 3	$ 14
Other deferred charges and assets/Other deferred credits and liabilities	**1**	**2**	—	—
Interest rate derivatives:				
Other current assets/Other current liabilities	**—**	**19**	1	4
Other deferred charges and assets/Other deferred credits and liabilities	**—**	**30**	—	34
Foreign currency derivatives:				
Other current assets/Other current liabilities	**—**	**23**	—	23
Other deferred charges and assets/Other deferred credits and liabilities	**75**	**—**	129	—
Total derivatives designated as hedging instruments in cash flow and fair value hedges	**$ 79**	**$ 81**	$ 133	$ 75
Derivatives not designated as hedging instruments				
Energy-related derivatives:				
Other current assets/Other current liabilities	**$ 561**	**$ 575**	$ 380	$ 437
Other deferred charges and assets/Other deferred credits and liabilities	**180**	**325**	170	215
Total derivatives not designated as hedging instruments	**$ 741**	**$ 900**	$ 550	$ 652
Gross amounts recognized	**$ 837**	**$ 1,036**	$ 700	$ 794
Gross amounts offset[(a)]	**$ (524)**	**$ (801)**	$ (405)	$ (598)
Net amounts recognized in the Balance Sheets[(b)]	**$ 313**	**$ 235**	$ 295	$ 196

	2018		2017	
Derivative Category and Balance Sheet Location	**Assets**	**Liabilities**	**Assets**	**Liabilities**
		(in millions)		
Alabama Power				
Derivatives designated as hedging instruments for regulatory purposes				
Energy-related derivatives:				
Other current assets/Other current liabilities	**$ 3**	**$ 4**	$ 2	$ 6
Other deferred charges and assets/Other deferred credits and liabilities	**3**	**6**	2	4
Total derivatives designated as hedging instruments for regulatory purposes	**$ 6**	**$ 10**	$ 4	$ 10
Gross amounts recognized	**$ 6**	**$ 10**	$ 4	$ 10
Gross amounts offset	**$ (4)**	**$ (4)**	$ (4)	$ (4)
Net amounts recognized in the Balance Sheets	**$ 2**	**$ 6**	$ —	$ 6
Georgia Power				
Derivatives designated as hedging instruments for regulatory purposes				
Energy-related derivatives:				
Other current assets/Other current liabilities	**$ 2**	**$ 8**	$ 2	$ 9
Other deferred charges and assets/Other deferred credits and liabilities	**4**	**13**	4	10
Total derivatives designated as hedging instruments for regulatory purposes	**$ 6**	**$ 21**	$ 6	$ 19
Derivatives designated as hedging instruments in cash flow and fair value hedges				
Interest rate derivatives:				
Other current assets/Other current liabilities	**$ —**	**$ 2**	$ —	$ 4
Other deferred charges and assets/Other deferred credits and liabilities	**—**	**—**	—	1
Total derivatives designated as hedging instruments in cash flow and fair value hedges	**$ —**	**$ 2**	$ —	$ 5
Gross amounts recognized	**$ 6**	**$ 23**	$ 6	$ 24
Gross amounts offset	**$ (6)**	**$ (6)**	$ (6)	$ (6)
Net amounts recognized in the Balance Sheets	**$ —**	**$ 17**	$ —	$ 18

	2018		2017	
Derivative Category and Balance Sheet Location	**Assets**	**Liabilities**	**Assets**	**Liabilities**
		(in millions)		
Mississippi Power				
Derivatives designated as hedging instruments for regulatory purposes				
Energy-related derivatives:				
Other current assets/Other current liabilities	**$ 1**	**$ 3**	$ 1	$ 6
Other deferred charges and assets/Other deferred credits and liabilities	**2**	**6**	1	3
Total derivatives designated as hedging instruments for regulatory purposes	**$ 3**	**$ 9**	$ 2	$ 9
Gross amounts recognized	**$ 3**	**$ 9**	$ 3	$ 9
Gross amounts offset	**$ (2)**	**$ (2)**	$ (2)	$ (2)
Net amounts recognized in the Balance Sheets	**$ 1**	**$ 7**	$ 1	$ 7
Southern Power				
Derivatives designated as hedging instruments in cash flow and fair value hedges				
Energy-related derivatives:				
Other current assets/Other current liabilities	**$ 3**	**$ 6**	$ 3	$ 11
Other deferred charges and assets/Other deferred credits and liabilities	**1**	**2**	—	—
Foreign currency derivatives:				
Other current assets/Other current liabilities	**—**	**23**	—	23
Other deferred charges and assets/Other deferred credits and liabilities	**75**	**—**	129	—
Total derivatives designated as hedging instruments in cash flow and fair value hedges	**$ 79**	**$ 31**	$ 132	$ 34
Derivatives not designated as hedging instruments				
Energy-related derivatives:				
Other current assets/Other current liabilities	**$ —**	**$ —**	$ —	$ 2
Total derivatives not designated as hedging instruments	**$ —**	**$ —**	$ —	$ 2
Gross amounts recognized	**$ 79**	**$ 31**	$ 132	$ 36
Gross amounts offset	**$ (3)**	**$ (3)**	$ (3)	$ (3)
Net amounts recognized in the Balance Sheets	**$ 76**	**$ 28**	$ 129	$ 33

	2018		2017	
Derivative Category and Balance Sheet Location	**Assets**	**Liabilities**	**Assets**	**Liabilities**
		(in millions)		
Southern Company Gas				
Derivatives designated as hedging instruments for regulatory purposes				
Energy-related derivatives:				
Assets from risk management activities/Liabilities from risk management activities-current	**$ 2**	**$ 8**	$ 5	$ 8
Other deferred charges and assets/Other deferred credits and liabilities	**—**	**1**	—	—
Total derivatives designated as hedging instruments for regulatory purposes	**$ 2**	**$ 9**	$ 5	$ 8
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	**$ —**	**$ 1**	$ —	$ 3
Total derivatives designated as hedging instruments in cash flow and fair value hedges	**$ —**	**$ 1**	$ —	$ 3
Derivatives not designated as hedging instruments				
Energy-related derivatives:				
Assets from risk management activities/Liabilities from risk management activities-current	**$ 559**	**$ 574**	$ 379	$ 434
Other deferred charges and assets/Other deferred credits and liabilities	**180**	**325**	170	215
Total derivatives not designated as hedging instruments	**$ 739**	**$ 899**	$ 549	$ 649
Gross amounts recognized	**$ 741**	**$ 909**	$ 554	$ 660
Gross amounts offset[(a)]	**$ (508)**	**$ (785)**	$ (390)	$ (583)
Net amounts recognized in the Balance Sheets [(b)]	**$ 233**	**$ 124**	$ 164	$ 77

(a) Gross amounts offset include cash collateral held on deposit in broker margin accounts of $277 million and $193 million at December 31, 2018 and 2017, respectively.

(b) Net amounts of derivative instruments outstanding exclude premium and intrinsic value associated with weather derivatives of $8 million and $11 million at December 31, 2018 and 2017, respectively.

Energy-related derivatives not designated as hedging instruments were immaterial for Alabama Power, Georgia Power, Mississippi Power, and Southern Power at December 31, 2018 and 2017.

At December 31, 2018 and 2017, the pre-tax effects of unrealized derivative gains (losses) arising from energy-related derivative instruments designated as regulatory hedging instruments and deferred were as follows:

Regulatory Hedge Unrealized Gain (Loss) Recognized in the Balance Sheet at December 31, 2018

Derivative Category and Balance Sheet Location	Southern Company	Alabama Power	Georgia Power	Mississippi Power	Southern Company Gas
			(in millions)		
Energy-related derivatives:					
Other regulatory assets, current	$ (19)	$ (3)	$ (6)	$ (2)	$ (8)
Other regulatory assets, deferred	(16)	(3)	(9)	(4)	—
Assets held for sale, current	(6)	—	—	—	—
Other regulatory liabilities, current	1	—	—	—	1
Total energy-related derivative gains (losses)	$ (40)	$ (6)	$ (15)	$ (6)	$ (7)

Regulatory Hedge Unrealized Gain (Loss) Recognized in the Balance Sheet at December 31, 2017

Derivative Category and Balance Sheet Location	Southern Company[(*)]	Alabama Power	Georgia Power	Mississippi Power	Southern Company Gas[(*)]
			(in millions)		
Energy-related derivatives:					
Other regulatory assets, current	$ (34)	$ (4)	$ (7)	$ (5)	$ (4)
Other regulatory assets, deferred	(18)	(3)	(6)	(2)	—
Other regulatory liabilities, current	7	1	—	—	7
Other regulatory liabilities, deferred	1	—	—	—	—
Total energy-related derivative gains (losses)	$ (44)	$ (6)	$ (13)	$ (7)	$ 3

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

For the years ended December 31, 2018, 2017, and 2016, the pre-tax effects of cash flow hedge accounting on AOCI for the applicable registrants were as follows:

Gain (Loss) Recognized in OCI on Derivative	2018	2017	2016
		(in millions)	
Southern Company			
Energy-related derivatives	$ 17	$ (47)	$ 18
Interest rate derivatives	(1)	(2)	(180)
Foreign currency derivatives	(78)	140	(58)
Total	$ (62)	$ 91	$ (220)
Southern Power			
Energy-related derivatives	$ 10	$ (38)	$ 14
Foreign currency derivatives	(78)	140	(58)
Total	$ (68)	$ 102	$ (44)

Gain (Loss) Recognized in OCI on Derivative	Successor			Predecessor
	Year Ended December 31, 2018	Year Ended December 31, 2017	July 1, 2016 through December 31, 2016	January 1, 2016 through June 30, 2016
		(in millions)		*(in millions)*
Southern Company Gas				
Energy-related derivatives	**$ 7**	$ (9)	$ 2	$ —
Interest rate derivatives	**—**	—	(5)	(64)
Total	**$ 7**	$ (9)	$ (3)	$ (64)

For all years presented, the pre-tax effects of energy-related derivatives and interest rate derivatives designated as cash flow hedging instruments on AOCI were immaterial for the other registrants. In addition, for the years ended December 31, 2017 and 2016, there was no material ineffectiveness recorded in earnings for any registrant. Upon the adoption of ASU 2017-12, beginning in 2018, ineffectiveness was no longer separately measured and recorded in earnings. See Note 1 for additional information.

The pre-tax effects of cash flow and fair value hedge accounting on income for the years ended December 31, 2018, 2017, and 2016 were as follows:

Location and Amount of Gain (Loss) Recognized in Income on Cash Flow and Fair Value Hedging Relationships	2018	2017	2016
		(in millions)	
Southern Company			
Total cost of natural gas	**$ 1,539**	**$ 1,601**	**$ 613**
Gain (loss) on energy-related cash flow hedges[(a)]	2	(2)	(1)
Total depreciation and amortization	**3,131**	**3,010**	**2,502**
Gain (loss) on energy-related cash flow hedges[(a)]	7	(16)	2
Total interest expense, net of amounts capitalized	**(1,842)**	**(1,694)**	**(1,317)**
Gain (loss) on interest rate cash flow hedges[(a)]	(21)	(21)	(18)
Gain (loss) on foreign currency cash flow hedges[(a)]	(24)	(23)	(13)
Gain (loss) on interest rate fair value hedges[(b)]	(12)	(22)	(21)
Total other income (expense), net	**114**	**163**	**50**
Gain (loss) on foreign currency cash flow hedges[(a)(c)]	(60)	160	(82)
Alabama Power			
Total interest expense, net of amounts capitalized	**$ (323)**	**$ (305)**	**$ (302)**
Gain (loss) on interest rate cash flow hedges[(a)]	(6)	(6)	(6)
Georgia Power			
Total interest expense, net of amounts capitalized	**$ (397)**	**$ (419)**	**$ (388)**
Gain (loss) on interest rate cash flow hedges[(a)]	(4)	(4)	(4)
Gain (loss) on interest rate fair value hedges[(b)]	2	(3)	(1)
Mississippi Power			
Total interest expense, net of amounts capitalized	**$ (76)**	**$ (42)**	**$ (74)**
Gain (loss) on interest rate cash flow hedges[(a)]	(2)	(2)	3
Southern Power			
Total depreciation and amortization	**$ 493**	**$ 503**	**$ 352**
Gain (loss) on energy-related cash flow hedges[(a)]	7	(17)	2
Total interest expense, net of amounts capitalized	**(183)**	**(191)**	**(117)**
Gain (loss) on foreign currency cash flow hedges[(a)]	(24)	(23)	(13)
Total other income (expense), net	**23**	**1**	**6**
Gain (loss) on foreign currency cash flow hedges[(a)(c)]	(60)	159	(82)

(a) Reclassified from AOCI into earnings.

(b) For fair value hedges, changes in the fair value of the derivative contracts are generally equal to changes in the fair value of the underlying debt and have no material impact on income.

(c) The reclassification from AOCI into other income (expense), net completely offsets currency gains and losses arising from changes in the U.S. currency exchange rates used to record the euro-denominated notes.

Location and Amount of Gain (Loss) Recognized in Income on Cash Flow and Fair Value Hedging Relationships	Successor			Predecessor
	Year Ended December 31, 2018	Year Ended December 31, 2017	July 1, 2016 through December 31, 2016	January 1, 2016 through June 30, 2016
	(in millions)			(in millions)
Southern Company Gas				
Total cost of natural gas	**$ 1,539**	**$ 1,601**	**$ 613**	**$ 755**
Gain (loss) on energy-related cash flow hedges(*)	2	(2)	(1)	(1)

(*) Amounts reflect gains or losses on cash flow hedges that were reclassified from AOCI into earnings.

The pre-tax effects of cash flow hedge accounting on income for interest rate derivatives were immaterial for all other registrants for all years presented.

At December 31, 2018 and 2017, the following amounts were recorded on the balance sheets related to cumulative basis adjustments for fair value hedges:

Balance Sheet Location of Hedged Items	Carrying Amount of the Hedged Item		Cumulative Amount of Fair Value Hedging Adjustment included in Carrying Amount of the Hedged Item	
	At December 31, 2018	At December 31, 2017	At December 31, 2018	At December 31, 2017
	(in millions)		(in millions)	
Southern Company				
Securities due within one year	$ (498)	$ (746)	$ 2	$ 3
Long-term debt	(2,052)	(2,553)	41	35
Georgia Power				
Securities due within one year	$ (498)	$ (746)	$ 2	$ 3
Long-term debt	—	(498)	—	1

The pre-tax effects of energy-related derivatives not designated as hedging instruments on the statements of income for the years ended December 31, 2018, 2017, and 2016 for the applicable registrants were as follows:

Derivatives in Non-Designated Hedging Relationships	Statements of Income Location	Gain (Loss)		
		2018	2017	2016
			(in millions)	
Southern Company				
Energy-related derivatives	Natural gas revenues(*)	**$ (122)**	$ (80)	$ 33
	Cost of natural gas	**(6)**	(2)	3
	Wholesale electric revenues	**2**	(4)	2
Total derivatives in non-designated hedging relationships		**$ (126)**	$ (86)	$ 38

(*) Excludes the impact of weather derivatives recorded in natural gas revenues of $5 million, $23 million, and $6 million for the years ended December 31, 2018, 2017, and 2016, respectively, as they are accounted for based on intrinsic value rather than fair value.

Derivatives in Non-Designated Hedging Relationships	Statements of Income Location	Gain (Loss) Successor For the Year Ended December 31, 2018	Successor For the Year Ended December 31, 2017	Successor July 1, 2016 through December 31, 2016	Predecessor January 1, 2016 through June 30, 2016
				(in millions)	*(in millions)*
Southern Company Gas					
Energy-related derivatives	Natural gas revenues(*)	**$ (122)**	$ (80)	$ 33	$ (1)
	Cost of natural gas	**(6)**	(2)	3	(62)
Total derivatives in non-designated hedging relationships		**$ (128)**	$ (82)	$ 36	$ (63)

(*) Excludes the impact of weather derivatives recorded in natural gas revenues of $5 million and $23 million for the successor years ended December 31, 2018 and 2017, respectively, $6 million for the successor period of July 1, 2016 through December 31, 2016, and $3 million for the predecessor period of January 1, 2016 through June 30, 2016, as they are accounted for based on intrinsic value rather than fair value.

The pre-tax effects of energy-related derivatives and interest rate derivatives not designated as hedging instruments were immaterial for all other registrants for all years presented.

Contingent Features

Southern Company, the traditional electric operating companies, Southern Power, and Southern Company Gas do 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, 2018, the registrants had no collateral posted with derivative counterparties to satisfy these arrangements.

For the registrants with interest rate derivatives at December 31, 2018, the fair value of interest rate derivative liabilities with contingent features and the maximum potential collateral requirements arising from the credit-risk-related contingent features, at a rating below BBB- and/or Baa3, was immaterial. At December 31, 2018, the fair value of energy-related derivative liabilities with contingent features and the maximum potential collateral requirements arising from the credit-risk-related contingent features, at a rating below BBB- and/or Baa3, were immaterial for all registrants. The maximum potential collateral requirements arising from the credit-risk-related contingent features for the traditional electric operating companies and Southern Power include certain agreements that could require collateral in the event that one or more Southern Company power pool participants has a credit rating change to below investment grade. Following the sale of Gulf Power to NextEra Energy, Gulf Power is continuing to participate in the Southern Company power pool for a defined transition period that, subject to certain potential adjustments, is scheduled to end on January 1, 2024.

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.

Alabama Power and Southern Power maintain 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, Alabama Power and Southern Power may be required to post collateral. At December 31, 2018, 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 Gas may be required to deposit cash into these accounts. At December 31, 2018, cash collateral held on deposit in broker margin accounts was $277 million.

The registrants are exposed to losses related to financial instruments in the event of counterparties' nonperformance. The registrants only enter 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 registrants have also established risk management policies and controls to determine and monitor the creditworthiness of counterparties in order to mitigate their exposure to counterparty credit risk. Prior to entering into a physical transaction, Southern Company Gas 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. Southern Company Gas may require counterparties to pledge additional collateral when deemed necessary.

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

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

The registrants do not anticipate a material adverse effect on their respective financial statements as a result of counterparty nonperformance.

15. ACQUISITIONS AND DISPOSITIONS

Southern Company Merger with Southern Company Gas

On July 1, 2016, Southern Company completed the Merger for a total purchase price of approximately $8.0 billion and Southern Company Gas became a wholly-owned, direct subsidiary of Southern Company. 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 Southern Company Gas RSUs, restricted stock awards, non-employee director stock awards, stock options, and PSUs were either redeemed or converted into Southern Company RSUs. See Note 12 for additional information.

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, which represents a different basis of accounting from Southern Company Gas' historical basis prior to the Merger. The following table presents the final purchase price allocation:

	Southern Company Gas Successor	Southern Company Gas Predecessor	
Southern Company Gas Purchase Price	**New Basis**	**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	$ 8,001	$ 3,933	$ 4,068

Southern Company Gas' Results of Operations and Pro Forma Financial Information

The results of operations for Southern Company Gas have been included in Southern Company's consolidated financial statements from the date of acquisition and consisted of operating revenues of $1.7 billion and net income of $114 million in 2016.

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
Operating revenues (in millions)	$	21,791
Net income attributable to Southern Company (in millions)	$	2,591
Basic EPS	$	2.70
Diluted EPS	$	2.68

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.

Southern Company Acquisition of PowerSecure

In May 2016, Southern Company acquired all of the outstanding stock of PowerSecure for $18.75 per common share in cash, resulting in an aggregate purchase price of $429 million. As a result, PowerSecure became a wholly-owned subsidiary of Southern Company.

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 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 Company's Sale of Gulf Power

On January 1, 2019, Southern Company completed the sale of all of the capital stock of Gulf Power to 700 Universe, LLC, a wholly-owned subsidiary of NextEra Energy, for an aggregate cash purchase price of approximately $5.8 billion (less $1.3 billion of indebtedness assumed), subject to customary working capital adjustments.

The assets and liabilities of Gulf Power are classified as assets held for sale and liabilities held for sale on Southern Company's balance sheet as of December 31, 2018. See "Assets Held for Sale" herein for additional information.

Southern Power

During 2018 and 2017, Southern Power or one of its wholly-owned subsidiaries acquired or completed construction of the facilities discussed below. Acquisition-related costs were expensed as incurred and were not material for any of the years presented.

Acquisitions During the Year Ended December 31, 2018

During 2018, Southern Power acquired and completed the project below and acquired the Wild Horse Mountain and Reading wind facilities discussed under "Construction Projects Completed and/or in Progress" below.

Project Facility	Resource	Seller, Acquisition Date	Approximate Nameplate Capacity (*MW*)	Location	Ownership Percentage	Actual COD	PPA Contract Period
Gaskell West 1	Solar	Recurrent Energy Development Holdings, LLC, January 26, 2018	20	Kern County, CA	100% of Class B (*)	March 2018	20 years

(*) Southern Power owns 100% of the class B membership interests under a tax equity partnership.

The Gaskell West 1 facility did not have operating revenues or activities prior to being placed in service during March 2018.

Acquisitions During the Year Ended December 31, 2017

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

Project Facility	Resource	Seller, Acquisition Date	Approximate Nameplate Capacity (*MW*)	Location	Ownership Percentage	Actual COD	PPA Contract Period
Bethel	Wind	Invenergy Wind Global LLC, January 6, 2017	276	Castro County, TX	100%	January 2017	12 years
Cactus Flats(*)	Wind	RES America Developments, Inc., July 31, 2017	148	Concho County, TX	100%	July 2018	12 years and 15 years

(*) On July 31, 2017, Southern Power purchased 100% of the Cactus Flats facility. In August 2018, Southern Power closed on a tax equity partnership and owns 100% of the class B membership interests.

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, were recognized in the consolidated statements of income 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 was still under construction. Therefore, supplemental pro forma information as though the acquisitions occurred as of the beginning of 2017 is not meaningful and has been omitted.

Construction Projects Completed and/or in Progress

During 2018, in accordance with its growth strategy, Southern Power started, continued, or completed construction of the projects set forth in the table below. Total aggregate construction costs, excluding the acquisition costs, are expected to be between $575 million and $640 million for the Plant Mankato expansion, Wild Horse Mountain, and Reading facilities. At December 31, 2018, construction costs included in CWIP related to these projects totaled $289 million, except for the Plant Mankato expansion which is classified as assets held for sale in the financial statements. The ultimate outcome of these matters cannot be determined at this time.

Project Facility	Resource	Approximate Nameplate Capacity (*MW*)	Location	Actual/ Expected COD	PPA Counterparties	PPA Contract Period
Construction Projects Completed During the Year Ended December 31, 2018						
Cactus Flats[a]	Wind	148	Concho County, TX	July 2018	General Motors, LLC and General Mills Operations, LLC	12 years and 15 years
Projects Under Construction at December 31, 2018						
Mankato expansion[b]	Natural Gas	385	Mankato, MN	Second quarter 2019	Northern States Power Company	20 years
Wild Horse Mountain[c]	Wind	100	Pushmataha County, OK	Fourth quarter 2019	Arkansas Electric Cooperative	20 years
Reading[d]	Wind	200	Osage and Lyon Counties, KS	Second quarter 2020	Royal Caribbean Cruises LTD	12 years

(a) In July 2017, Southern Power purchased 100% of the Cactus Flats facility. In August 2018, Southern Power closed on a tax equity partnership and now owns 100% of the class B membership interests.

(b) In November 2018, Southern Power entered into an agreement to sell all of its equity interests in Plant Mankato, including this expansion currently under construction. See "Sales of Natural Gas Plants" below.

(c) In May 2018, Southern Power purchased 100% of the Wild Horse Mountain facility. Southern Power may enter into a tax equity partnership, in which case it would then own 100% of the class B membership interests. The ultimate outcome of this matter cannot be determined at this time.

(d) In August 2018, Southern Power purchased 100% of the membership interests of the Reading facility from the joint development arrangement with Renewable Energy Systems Americas, Inc. described below. Southern Power may enter into a tax equity partnership, in which case it would then own 100% of the class B membership interests. The ultimate outcome of this matter cannot be determined at this time.

Development Projects

During 2017, Southern Power purchased wind turbine equipment to be used for various development and construction projects. Any wind projects using this equipment and reaching commercial operation by the end of 2021 are expected to qualify for 80% PTCs.

During 2016, Southern Power entered into a joint development agreement with Renewable Energy Systems Americas, Inc. (RES) to develop and construct wind projects. Concurrent with the agreement, Southern Power purchased wind turbine equipment from Siemens Wind Power, Inc. and Vestas-American Wind Technology, Inc. to be used for construction of these projects. Several wind projects using this equipment, as well as other purchased equipment, have successfully originated, directly or indirectly, from the partnership with RES and are expected to reach commercial operation before the end of 2020, thus qualifying for 100% PTCs.

Southern Power continues to evaluate and refine the deployment of the wind turbine equipment to potential joint development and construction projects as well as the amount of MW capacity to be constructed. During the third quarter 2018, as a result of a review of various options for probable dispositions of wind turbine equipment not deployed to development or construction projects, Southern Power recorded a $36 million asset impairment charge on the equipment.

Subsequent to December 31, 2018 and as part of management's continuous review of disposition options, approximately $53 million of this equipment is being marketed for sale and will be classified as held for sale.

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

Sales of Renewable Facility Interests

On May 22, 2018, Southern Power completed the sale of a noncontrolling 33% equity interest in SP Solar, a limited partnership indirectly owning substantially all of Southern Power's solar facilities, to Global Atlantic for approximately $1.2 billion. Since Southern Power retains control of the limited partnership through its wholly-owned general partner, the sale was recorded as an

equity transaction and Southern Power will continue to consolidate SP Solar in its financial statements. On the date of the transaction, the noncontrolling interest was increased by $511 million to reflect 33% of the carrying value of the partnership. This difference, partially offset by the tax impact and other related transaction charges, also resulted in a $410 million decrease to Southern Power's common stockholder's equity.

On December 11, 2018, Southern Power completed the sale of a noncontrolling tax equity interest in SP Wind, which owns a portfolio of eight operating wind facilities, to three financial investors for approximately $1.2 billion. Since Southern Power retains control of SP Wind, it will continue to consolidate SP Wind in its financial statements. The tax equity investors together will generally receive 40% of the cash distributions from available cash and will receive a 99% allocation of tax attributes, including future PTCs.

Sales of Natural Gas Plants

On December 4, 2018, Southern Power completed the sale of all of its equity interests in the Florida Plants to NextEra Energy for $203 million. In contemplation of this sale transaction, Southern Power recorded an asset impairment charge of approximately $119 million ($89 million after tax) in May 2018.

On November 5, 2018, Southern Power entered into an agreement with Northern States Power to sell all of its equity interests in Plant Mankato (including the 385-MW expansion currently under construction) for an aggregate purchase price of approximately $650 million. The completion of the disposition is subject to the expansion unit reaching commercial operation as well as various other customary conditions to closing, including working capital and timing adjustments. The ultimate purchase price will decrease $66,667 per day for each day after June 1, 2019 that the expansion has not achieved commercial operation, not to exceed $15 million. This transaction is subject to FERC and state commission approvals and is expected to close in mid-2019. The assets and liabilities of Plant Mankato are classified as assets held for sale and liabilities held for sale on Southern Company's and Southern Power's balance sheet as of December 31, 2018. See "Assets Held for Sale" herein for additional information. The ultimate outcome of this matter cannot be determined at this time.

Southern Company Gas

See "Southern Company Merger with Southern Company Gas" herein for information regarding the Merger.

Investment in SNG

In 2016, Southern Company Gas, through a wholly-owned, indirect subsidiary, acquired a 50% equity interest in SNG from Kinder Morgan, Inc. for $1.4 billion. 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 exceeded the underlying ownership interest in the net assets of SNG by approximately $700 million. This basis difference was 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.

In March 2017, Southern Company Gas made an additional $50 million contribution to maintain its 50% equity interest in SNG. See Note 7 under "Southern Company Gas" for additional information on this investment.

Southern Company Gas' investment in SNG decreased by $104 million at December 31, 2017 related to the impact of the Tax Reform Legislation and new income tax apportionment factors in several states resulting from Southern Company Gas' inclusion in the consolidated Southern Company state tax filings.

Sale of Pivotal Home Solutions

On June 4, 2018, Southern Company Gas completed the stock sale of Pivotal Home Solutions to American Water Enterprises LLC for a total cash purchase price of $365 million, which includes the final working capital adjustment. This disposition resulted in a net loss of $67 million, which includes $34 million of income tax expense. In contemplation of the transaction, a goodwill impairment charge of $42 million was recorded during the first quarter 2018. The income tax expense included tax on goodwill not deductible for tax purposes and for which a deferred tax liability had not been recorded previously. Southern Company Gas and American Water Enterprises LLC entered into a transition services agreement whereby Southern Company Gas provided certain administrative and operational services through November 4, 2018.

Sale of Elizabethtown Gas and Elkton Gas

On July 1, 2018, a Southern Company Gas subsidiary, Pivotal Utility Holdings, completed the sales 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, which includes the final working capital and other adjustments. This disposition resulted in a pre-tax gain that was entirely offset by $205 million of income tax expense, resulting in no material net income impact. The income tax expense included tax on goodwill not deductible for tax purposes and for which a deferred tax liability had not been recorded previously. Southern Company Gas and South Jersey Industries, Inc. entered into transition services agreements whereby Southern Company Gas will provide certain administrative and operational services through no later than July 31, 2020.

Sale of Florida City Gas

On July 29, 2018, Southern Company Gas and its wholly-owned direct subsidiary, NUI Corporation, completed the stock sale of Pivotal Utility Holdings, which primarily consisted of Florida City Gas, to NextEra Energy for a total cash purchase price of $587 million, which includes the final working capital adjustment. This disposition resulted in a net gain of $16 million, which includes $103 million of income tax expense. The income tax expense included tax on goodwill not deductible for tax purposes and for which a deferred tax liability had not been recorded previously. Southern Company Gas and NextEra Energy entered into a transition services agreement whereby Southern Company Gas will provide certain administrative and operational services through no later than July 29, 2020.

Assets Held for Sale

As discussed previously, Southern Company and Southern Power each have assets and liabilities held for sale on their balance sheets at December 31, 2018. Assets and liabilities held for sale have been classified separately on each company's balance sheet at the lower of carrying value or fair value less costs to sell at the time the criteria for held-for-sale classification were met. For assets and liabilities held for sale recorded at fair value on a nonrecurring basis, the fair value of assets held for sale is based primarily on unobservable inputs (Level 3), which includes the agreed upon sales prices in executed sales agreements.

Upon classification as held for sale in May 2018 for the Florida Plants and November 2018 for Plant Mankato, Southern Power ceased recognizing depreciation on the property, plant, and equipment to be sold. The Florida Plants sale was completed on December 4, 2018. Since the depreciation of the assets sold in the Gulf Power transaction continued to be reflected in customer rates through the closing date and was reflected in the carryover basis of the assets when sold, Southern Company continued to record depreciation on those assets through the date the transaction closed. Likewise, since the depreciation of the assets sold in the Elizabethtown Gas, Elkton Gas, and Florida City Gas transactions continued to be reflected in customer rates and was reflected in the carryover basis of the assets when sold, Southern Company Gas continued to record depreciation on those assets through the respective date that each transaction closed.

The following table provides Southern Company's and Southern Power's major classes of assets and liabilities classified as held for sale at December 31, 2018:

	Southern Company	Southern Power
	(in millions)	
Assets Held for Sale:		
Current assets	$ 393	$ 8
Total property, plant, and equipment	4,623	576
Other non-current assets	727	—
Total Assets Held for Sale	$ 5,743	$ 584
Liabilities Held for Sale:		
Current liabilities	$ 425	$ 15
Long-term debt	1,286	—
Accumulated deferred income taxes	618	—
Other non-current liabilities	932	—
Total Liabilities Held for Sale	$ 3,261	$ 15

Southern Company, Southern Power, and Southern Company Gas each concluded that the asset sales, both individually and combined, did not represent a strategic shift in operations that has, or is expected to have, a major effect on its operations and financial results; therefore, none of the assets related to the sales have been classified as discontinued operations for any of the periods presented.

Gulf Power and the Florida Plants represent individually significant components of Southern Company and Southern Power, respectively; therefore, pre-tax income for these components for the years ended December 31, 2018, 2017, and 2016 are presented below:

	2018	2017	2016
		(in millions)	
Earnings (loss) before income taxes:			
Gulf Power	$ 140	$ 229	$ 231
Southern Power's Florida Plants(*)	$ 49	$ 37	$ 37

(*) Earnings before income taxes for the Florida Plants in 2018 represents the period from January 1, 2018 to December 4, 2018 (the divestiture date).

16. SEGMENT AND RELATED INFORMATION

Southern Company

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 traditional electric operating companies – Alabama Power, Georgia Power, Gulf Power (through December 31, 2018), and Mississippi Power – are vertically integrated utilities providing electric service in four Southeastern states. On January 1, 2019, Southern Company completed its sale of Gulf Power to NextEra Energy. 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 its natural gas distribution utilities and is involved in several other complementary businesses including gas pipeline investments, wholesale gas services, and gas marketing services. In July 2018, Southern Company Gas completed sales of three of its natural gas distribution utilities. See Note 15 for additional information regarding disposition activities.

Southern Company's reportable business segments are the sale of electricity by the 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 $435 million, $392 million, and $419 million in 2018, 2017, and 2016, respectively. Revenues from sales of natural gas from Southern Company Gas to the traditional electric operating companies and Southern Power were $32 million and $119 million, respectively, in 2018, $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.

COMBINED NOTES TO FINANCIAL STATEMENTS (continued)
Southern Company and Subsidiary Companies 2018 Annual Report

Financial data for business segments and products and services for the years ended December 31, 2018, 2017, and 2016 was as follows:

	Electric Utilities							
	Traditional Electric Operating Companies	Southern Power	Eliminations	Total	Southern Company Gas	All Other	Eliminations	Consolidated
				(in millions)				
2018								
Operating revenues	**$ 16,843**	**$ 2,205**	**$ (477)**	**$ 18,571**	**$ 3,909**	**$ 1,213**	**$ (198)**	**$ 23,495**
Depreciation and amortization	**2,072**	**493**	**—**	**2,565**	**500**	**66**	**—**	**3,131**
Interest income	**23**	**8**	**—**	**31**	**4**	**8**	**(5)**	**38**
Earnings from equity method investments	**(1)**	**—**	**—**	**(1)**	**148**	**2**	**(1)**	**148**
Interest expense	**852**	**183**	**—**	**1,035**	**228**	**580**	**(1)**	**1,842**
Income taxes (benefit)	**371**	**(164)**	**—**	**207**	**464**	**(222)**	**—**	**449**
Segment net income (loss)[(a)(b)(c)(d)]	**2,117**	**187**	**—**	**2,304**	**372**	**(453)**	**3**	**2,226**
Goodwill	**—**	**2**		**2**	**5,015**	**298**	**—**	**5,315**
Total assets	**79,382**	**14,883**	**(306)**	**93,959**	**21,448**	**3,285**	**(1,778)**	**116,914**
Gross property additions	**6,077**	**315**	**—**	**6,392**	**1,399**	**414**	**—**	**8,205**
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 (benefit)	1,021	(939)	—	82	367	(307)	—	142
Segment net income (loss)[(a)(b)(e)(f)]	(193)	1,071	—	878	243	(279)	—	842
Goodwill	—	2	—	2	5,967	299	—	6,268
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 (benefit)	1,286	(195)	—	1,091	76	(216)	—	951
Segment net income (loss)[(a)(b)]	2,233	338	—	2,571	114	(230)	(7)	2,448
Goodwill	—	2	—	2	5,967	282	—	6,251
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

(a) Attributable to Southern Company.

(b) Segment net income (loss) for the traditional electric operating companies includes pre-tax charges for estimated losses on plants under construction of $1.1 billion ($722 million after tax) in 2018, $3.4 billion ($2.4 billion after tax) in 2017, and $428 million ($264 million after tax) in 2016. See Note 2 under "Georgia Power – Nuclear Construction" and "Mississippi Power – Kemper County Energy Facility – Schedule and Cost Estimate" for additional information.

(c) Segment net income (loss) for Southern Power includes pre-tax impairment charges of $156 million ($117 million after tax) in 2018. See Note 15 under "Southern Power – Development Projects" and " – Sales of Natural Gas Plants" for additional information.

(d) Segment net income (loss) for Southern Company Gas includes a net gain on dispositions of $291 million ($51 million loss after tax) in 2018 related to the Southern Company Gas Dispositions and a goodwill impairment charge of $42 million in 2018 related to the sale of Pivotal Home Solutions. See Note 15 under "Southern Company Gas" for additional information.

(e) Segment net income (loss) for the traditional electric operating companies 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 2 under "Southern Company – Gulf Power" for additional information.

(f) Segment net income (loss) includes income tax expense of $367 million for the traditional electric operating companies, income tax benefit of $743 million for Southern Power, and income tax expense of $93 million for Southern Company Gas in 2017 related to the Tax Reform Legislation.

Products and Services

Electric Utilities' Revenues

Year	Retail	Wholesale	Other	Total
		(in millions)		
2018	**$ 15,222**	**$ 2,516**	**$ 833**	**$ 18,571**
2017	15,330	2,426	784	18,540
2016	15,234	1,926	781	17,941

Southern Company Gas' Revenues

Year	Gas Distribution Operations	Gas Marketing Services	All Other	Total
		(in millions)		
2018	**$ 3,155**	**$ 568**	**$ 186**	**$ 3,909**
2017	3,024	860	36	3,920
2016	1,266	354	32	1,652

Southern Company Gas

Southern Company Gas manages its business through four reportable segments - gas distribution operations, gas pipeline investments, wholesale gas services, and gas marketing services. The non-reportable segments are combined and presented as all other. During 2018, Southern Company Gas changed its reportable segments to further align the way its new Chief Operating Decision Maker reviews operating results and has reclassified prior years' data to conform to the new reportable segment presentation. This change resulted in a new reportable segment, gas pipeline investments, which was formerly included in gas midstream operations.

Gas distribution operations is the largest component of Southern Company Gas' business and includes natural gas local distribution utilities that construct, manage, and maintain intrastate natural gas pipelines and gas distribution facilities in four states. In July 2018, Southern Company Gas sold three of its natural gas distribution utilities, Elizabethtown Gas, Elkton Gas, and Florida City Gas. See Note 15 under "Southern Company Gas" for additional information.

Gas pipeline investments consists of joint ventures in natural gas pipeline investments including a 50% interest in SNG, two significant pipeline construction projects, and a 50% joint ownership interest in the Dalton Pipeline. These natural gas pipelines enable the provision of diverse sources of natural gas supplies to the customers of Southern Company Gas. See Notes 5 and 7 for additional information.

Wholesale gas services provides natural gas asset management and/or related logistics services for each of Southern Company Gas' utilities except Nicor Gas as well as for non-affiliated companies. Additionally, wholesale gas services engages in natural gas storage and gas pipeline arbitrage and related activities.

Gas marketing services provides natural gas marketing to end-use customers primarily in Georgia and Illinois through SouthStar. On June 4, 2018, Southern Company Gas sold Pivotal Home Solutions, which provided home equipment protection products and services. See Note 15 under "Southern Company Gas – Sale of Pivotal Home Solutions" for additional information.

The all other column includes segments below the quantitative threshold for separate disclosure, including the storage and fuels operations, which was formerly included in gas midstream operations, and the other subsidiaries that fall below the quantitative threshold for separate disclosure.

After the Merger, Southern Company Gas changed the segment performance measure to net income, which is utilized by its parent company. In order to properly assess net income by segment, Southern Company Gas executed various intercompany note agreements to revise interest charges to its segments. Since such agreements did not exist in the predecessor period, Southern Company Gas is unable to provide the comparable net income for that period.

COMBINED NOTES TO FINANCIAL STATEMENTS (continued)
Southern Company and Subsidiary Companies 2018 Annual Report

Financial data for business segments for the successor years ended December 31, 2018 and 2017, the successor period of July 1, 2016 through December 31, 2016, and the predecessor period of January 1, 2016 through June 30, 2016 were as follows:

	Gas Distribution Operations[a][b]	Gas Pipeline Investments	Wholesale Gas Services[c]	Gas Marketing Services[b][d]	Total	All Other	Eliminations	Consolidated
				(in millions)				
Successor – Year ended December 31, 2018								
Operating revenues	**$ 3,186**	**$ 32**	**$ 144**	**$ 568**	**$ 3,930**	**$ 55**	**$ (76)**	**$ 3,909**
Depreciation and amortization	**409**	**5**	**2**	**37**	**453**	**47**	**—**	**500**
Operating income (loss)	**904**	**20**	**70**	**19**	**1,013**	**(98)**	**—**	**915**
Earnings from equity method investments	**—**	**145**	**—**	**—**	**145**	**3**	**—**	**148**
Interest expense	**(178)**	**(34)**	**(9)**	**(6)**	**(227)**	**(1)**	**—**	**(228)**
Income taxes (benefit)	**409**	**28**	**4**	**54**	**495**	**(31)**	**—**	**464**
Segment net income (loss)	**334**	**103**	**38**	**(40)**	**435**	**(63)**	**—**	**372**
Gross property additions	**1,429**	**32**	**—**	**6**	**1,467**	**54**	**—**	**1,521**
Successor – Total assets at December 31, 2018	**17,266**	**1,763**	**1,302**	**1,587**	**21,918**	**11,112**	**(11,582)**	**21,448**
Successor – Year ended December 31, 2017								
Operating revenues	$ 3,207	$ 17	$ 6	$ 860	$ 4,090	$ 64	$ (234)	$ 3,920
Depreciation and amortization	391	2	2	62	457	44	—	501
Operating income (loss)	645	10	(51)	113	717	(57)	—	660
Earnings from equity method investments	—	103	—	—	103	3	—	106
Interest expense	(153)	(26)	(7)	(5)	(191)	(9)	—	(200)
Income taxes[e]	178	109	—	24	311	56	—	367
Segment net income (loss)[e]	353	(22)	(57)	84	358	(115)	—	243
Gross property additions	1,330	117	1	9	1,457	51	—	1,508
Successor – Total assets at December 31, 2017	19,358	1,699	1,096	2,147	24,300	12,726	(14,039)	22,987
Successor – July 1, 2016 through December 31, 2016								
Operating revenues	$ 1,342	$ 3	$ 24	$ 354	$ 1,723	$ 31	$ (102)	$ 1,652
Depreciation and amortization	185	—	1	35	221	17	—	238
Operating income (loss)	225	1	(2)	27	251	(52)	—	199
Earnings from equity method investments	—	58	—	—	58	2	—	60
Interest expense	(105)	(10)	(3)	(1)	(119)	38	—	(81)
Income taxes (benefit)	51	21	(3)	7	76	—	—	76
Segment net income (loss)	77	29	—	19	125	(11)	—	114
Gross property additions	561	51	1	5	618	14	—	632
Successor – Total assets at December 31, 2016	19,453	1,659	1,127	2,084	24,323	11,697	(14,167)	21,853

COMBINED NOTES TO FINANCIAL STATEMENTS (continued)
Southern Company and Subsidiary Companies 2018 Annual Report

	Gas Distribution Operations[a][b]	Gas Pipeline Investments	Wholesale Gas Services[c]	Gas Marketing Services[b][d]	Total	All Other	Eliminations	Consolidated
				(in millions)				
Predecessor – January 1, 2016 through June 30, 2016								
Operating revenues	$ 1,575	$ 3	$ (32)	$ 435	$ 1,981	$ 26	$ (102)	$ 1,905
Depreciation and amortization	178	—	1	11	190	16	—	206
Operating income (loss)	353	3	(69)	109	396	(73)	—	323
EBIT	353	3	(68)	109	397	(69)	—	328
Gross property additions	484	40	1	4	529	19	—	548

(a) Operating revenues for the three gas distribution operations dispositions were $244 million, $399 million, and $168 million for the successor years ended December 31, 2018 and 2017 and the successor period of July 1, 2016 through December 31, 2016, respectively, and $215 million for the predecessor period ended June 30, 2016. See Note 15 under "Southern Company Gas" for additional information.

(b) Segment net income for gas distribution operations includes a gain on dispositions of $324 million ($16 million after tax) for the year ended December 31, 2018. Segment net income for gas marketing services includes a loss on disposition of $(33) million ($(67) million loss after tax) and a goodwill impairment charge of $42 million for the year ended December 31, 2018 recorded in contemplation of the sale of Pivotal Home Solutions. See Note 15 under "Southern Company Gas" for additional information.

(c) 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, 2018	**$ 6,955**	**$ 451**	**$ 7,406**	**$ 7,262**	**$ 144**
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
Predecessor – January 1, 2016 through June 30, 2016	2,500	143	2,643	2,675	(32)

(d) Operating revenues for the gas marketing services disposition were $55 million, $129 million, and $56 million for the successor years ended December 31, 2018 and 2017 and the successor period of July 1, 2016 through December 31, 2016, respectively, and $64 million for the predecessor period ended June 30, 2016 See Note 15 under "Southern Company Gas" for additional information.

(e) Includes the impact of the Tax Reform Legislation and new income tax apportionment factors in several states resulting from Southern Company Gas' inclusion in the consolidated Southern Company state tax filings.

17. QUARTERLY FINANCIAL INFORMATION (UNAUDITED)

The tables below provide summarized quarterly financial information for each registrant for 2018 and 2017. Each registrant's business is influenced by seasonal weather conditions.

Quarter Ended	Southern Company[a]	Alabama Power	Georgia Power[b]	Mississippi Power[c]	Southern Power[d]	Southern Company Gas[e]
			(in millions)			
March 2018						
Operating Revenues	$ 6,372	$ 1,473	$ 1,961	$ 302	$ 509	$ 1,639
Operating Income (Loss)	1,376	372	513	7	60	388
Net Income (Loss)	936	225	352	(7)	115	279
Net Income (Loss) Attributable to Registrant	938	225	352	(7)	121	279
June 2018						
Operating Revenues	$ 5,627	$ 1,503	$ 2,048	$ 297	$ 555	$ 730
Operating Income (Loss)	63	380	(472)	54	16	49
Net Income (Loss)	(127)	259	(396)	46	45	(31)
Net Income (Loss) Attributable to Registrant	(154)	259	(396)	46	22	(31)
September 2018						
Operating Revenues	$ 6,159	$ 1,740	$ 2,593	$ 358	$ 635	$ 492
Operating Income (Loss)	2,174	561	991	80	136	374
Net Income (Loss)	1,222	373	664	47	146	46
Net Income (Loss) Attributable to Registrant	1,164	373	664	47	92	46
December 2018						
Operating Revenues	$ 5,337	$ 1,316	$ 1,818	$ 308	$ 506	$ 1,048
Operating Income (Loss)	578	164	257	52	30	104
Net Income (Loss)	269	73	173	149	(60)	78
Net Income (Loss) Attributable to Registrant	278	73	173	149	(48)	78

(a) See notes (b), (c), (d), and (e) below.

(b) Georgia Power recorded an estimated probable loss of $1.1 billion in the second quarter 2018 to reflect its revised estimate to complete construction and start-up of Plant Vogtle Units 3 and 4. See Note 2 under "Georgia Power – Nuclear Construction" for additional information.

(c) As a result of the abandonment and related closure activities for the mine and gasifier-related assets at the Kemper County energy facility, Mississippi Power recorded total pre-tax charges to income of $44 million ($33 million after tax) in the first quarter 2018, immaterial amounts in the second and third quarters 2018, and a pre-tax credit to income of $9 million in the fourth quarter 2018. In addition, Mississippi Power recorded a credit to earnings of $95 million in the fourth quarter 2018 primarily resulting from the reduction of a valuation allowance for a state income tax NOL carryforward associated with the Kemper County energy facility. See Note 2 under "Mississippi Power – Kemper County Energy Facility" and Note 10 for additional information.

(d) Southern Power recorded pre-tax impairment charges of $119 million ($89 million after tax) in the second quarter 2018 in contemplation of the sale of the Florida Plants and $36 million ($27 million after tax) in the third quarter 2018 related to wind turbine equipment. See Note 15 under "Southern Power – Sales of Natural Gas Plants" and " – Development Projects" for additional information. As a result of the Tax Reform Legislation, Southern Power recorded income tax expense of $75 million in the fourth quarter 2018. See Note 10 for additional information.

(e) Southern Company Gas recorded a goodwill impairment charge of $42 million in the first quarter 2018 in contemplation of the sale of Pivotal Home Solutions. Southern Company Gas also recorded gains (losses) on dispositions in the second, third, and fourth quarters 2018 of $(36) million pre-tax and $(76) million after tax, $353 million pre-tax and $40 million after tax, and $(27) million pre-tax and $(15) million after tax, respectively. See Note 15 under "Southern Company Gas" for additional information.

COMBINED NOTES TO FINANCIAL STATEMENTS (continued)
Southern Company and Subsidiary Companies 2018 Annual Report

Quarter Ended	Southern Company[(a)(b)(c)]	Alabama Power	Georgia Power	Mississippi Power[(a)(b)]	Southern Power[(b)]	Southern Company Gas[(b)]
			(in millions)			
March 2017						
Operating Revenues	$ 5,771	$ 1,382	$ 1,832	$ 272	$ 450	$ 1,560
Operating Income (Loss)	1,252	361	483	(64)	65	389
Net Income (Loss)	665	174	260	(20)	66	239
Net Income (Loss) Attributable to Registrant	658	174	260	(20)	70	239
June 2017						
Operating Revenues	$ 5,430	$ 1,484	$ 2,048	$ 303	$ 529	$ 716
Operating Income (Loss)	(1,649)	440	621	(2,956)	112	95
Net Income (Loss)	(1,348)	230	347	(2,054)	104	49
Net Income (Loss) Attributable to Registrant	(1,381)	230	347	(2,054)	82	49
September 2017						
Operating Revenues	$ 6,201	$ 1,740	$ 2,546	$ 341	$ 618	$ 565
Operating Income (Loss)	1,991	601	1,017	49	159	67
Net Income (Loss)	1,109	325	580	40	154	15
Net Income (Loss) Attributable to Registrant	1,069	325	580	40	124	15
December 2017						
Operating Revenues	$ 5,629	$ 1,433	$ 1,884	$ 271	$ 478	$ 1,079
Operating Income (Loss)	739	255	452	(180)	32	109
Net Income (Loss)	500	119	227	(556)	793	(60)
Net Income (Loss) Attributable to Registrant	496	119	227	(556)	795	(60)

(a) As a result of revisions to the cost estimate for the Kemper IGCC and the project's June 2017 suspension, Mississippi Power recorded total pre-tax charges to income related to the Kemper IGCC of $108 million ($67 million after tax) in the first quarter 2017, $3.0 billion ($2.1 billion after tax) in the second quarter 2017, $34 million ($21 million after tax) in the third quarter 2017, and $208 million ($185 million after tax) in the fourth quarter 2017. See Note 2 under "Mississippi Power – Kemper County Energy Facility" for additional information.

(b) 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, comprised primarily of income tax expense of $372 million recorded at Mississippi Power, income tax benefit of $743 million recorded at Southern Power, and income tax expense of $93 million recorded at Southern Company Gas. See Note 10 for additional information.

(c) Gulf Power recorded a pre-tax charge of $33 million ($20 million after tax) for the write-down of its ownership in Plant Scherer Unit 3 in the first quarter 2017. See Note 2 under "Southern Company – Gulf Power" for additional information.

Southern Company

The table below provides quarterly per share financial information for Southern Company common stock for 2018 and 2017.

	Per Common Share		
Quarter Ended	**Basic Earnings**	**Diluted Earnings**	**Dividends**
March 2018	**$ 0.93**	**$ 0.92**	**$ 0.5800**
June 2018	**(0.15)**	**(0.15)**	**0.6000**
September 2018	**1.14**	**1.13**	**0.6000**
December 2018	**0.27**	**0.27**	**0.6000**
March 2017	$ 0.66	$ 0.66	$ 0.5600
June 2017	(1.38)	(1.37)	0.5800
September 2017	1.07	1.06	0.5800
December 2017	0.49	0.49	0.5800

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, 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.

	Page
Southern Company	II-434
Alabama Power	II-435
Georgia Power	II-436
Mississippi Power	II-437
Southern Power	II-438
Southern Company Gas	II-439

(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 in Item 8 herein of this Form 10-K. This report is not applicable to Alabama Power, Georgia 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, 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 2018 that have materially affected or are reasonably likely to materially affect Southern Company's, Alabama Power's, Georgia Power's, Mississippi Power's, Southern Power's, or Southern Company Gas' internal control over financial reporting.

MANAGEMENT'S REPORT ON INTERNAL CONTROL OVER FINANCIAL REPORTING
Southern Company and Subsidiary Companies 2018 Annual Report

The management of 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, 2018.

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, 2018, which is included herein.

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

/s/ Andrew W. Evans
Andrew W. Evans
Executive Vice President and Chief Financial Officer

February 19, 2019

MANAGEMENT'S REPORT ON INTERNAL CONTROL OVER FINANCIAL REPORTING
Alabama Power Company 2018 Annual Report

The management of Alabama Power 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 Alabama Power'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 Alabama Power's internal control over financial reporting was effective as of December 31, 2018.

/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 19, 2019

MANAGEMENT'S REPORT ON INTERNAL CONTROL OVER FINANCIAL REPORTING
Georgia Power Company 2018 Annual Report

The management of Georgia Power 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 Georgia Power'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 Georgia Power's internal control over financial reporting was effective as of December 31, 2018.

/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 19, 2019

MANAGEMENT'S REPORT ON INTERNAL CONTROL OVER FINANCIAL REPORTING
Mississippi Power Company 2018 Annual Report

The management of Mississippi Power 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 Mississippi Power'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 Mississippi Power's internal control over financial reporting was effective as of December 31, 2018.

/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 19, 2019

MANAGEMENT'S REPORT ON INTERNAL CONTROL OVER FINANCIAL REPORTING
Southern Power Company and Subsidiary Companies 2018 Annual Report

The management of Southern Power 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 Power'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 Power's internal control over financial reporting was effective as of December 31, 2018.

/s/ Mark S. Lantrip
Mark S. Lantrip
Chairman, President, and Chief Executive Officer

/s/ William C. Grantham
William C. Grantham
Senior Vice President, Chief Financial Officer, and Treasurer

February 19, 2019

MANAGEMENT'S REPORT ON INTERNAL CONTROL OVER FINANCIAL REPORTING
Southern Company Gas and Subsidiary Companies 2018 Annual Report

The management of Southern Company Gas 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 Gas' 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 Gas' internal control over financial reporting was effective as of December 31, 2018.

/s/ Kimberly S. Greene
Kimberly S. Greene
Chairman, President, and Chief Executive Officer

/s/ Daniel S. Tucker
Daniel S. Tucker
Executive Vice President, Chief Financial Officer, and Treasurer

February 19, 2019

Item 9B. OTHER INFORMATION

Georgia Power is disclosing the information below in this Item 9B in lieu of filing a Current Report on Form 8-K.

Amendments to the Vogtle Joint Ownership Agreements

As previously reported, on September 26, 2018, Georgia Power entered into a binding term sheet with the other Vogtle Owners and MEAG's wholly-owned subsidiaries MEAG Power SPVJ, LLC (MEAG SPVJ), MEAG Power SPVM, LLC (MEAG SPVM), and MEAG Power SPVP, LLC (MEAG SPVP) to take certain actions which partially mitigate potential financial exposure for the other Vogtle Owners (Vogtle Owner Term Sheet).

On February 18, 2019, Georgia Power, the other Vogtle Owners, MEAG SPVJ, MEAG SPVM, and MEAG SPVP entered into certain amendments to the joint ownership agreements for Plant Vogtle Units 3 and 4 (Vogtle Joint Ownership Agreements) to implement the provisions of the Vogtle Owner Term Sheet (Global Amendments).

Pursuant to the Global Amendments, and consistent with the Vogtle Owner Term Sheet, the Vogtle Joint Ownership Agreements were modified as follows: (i) each Vogtle Owner must pay its proportionate share of qualifying construction costs for Plant Vogtle Units 3 and 4 based on its ownership percentage up to the estimated cost at completion (EAC) for Plant Vogtle Units 3 and 4 which formed the basis of Georgia Power's forecast of $8.4 billion in the nineteenth VCM plus $800 million; (ii) Georgia Power will be responsible for 55.7% of actual qualifying construction costs between $800 million and $1.6 billion over the EAC in the nineteenth VCM (resulting in $80 million of potential additional costs to Georgia Power), with the remaining Vogtle Owners responsible for 44.3% of such costs pro rata in accordance with their respective ownership interests; and (iii) Georgia Power will be responsible for 65.7% of qualifying construction costs between $1.6 billion and $2.1 billion over the EAC in the nineteenth VCM (resulting in a further $100 million of potential additional costs to Georgia Power), with the remaining Vogtle Owners responsible for 34.3% of such costs pro rata in accordance with their respective ownership interests.

If the EAC is revised and exceeds the EAC in the nineteenth VCM by more than $2.1 billion, each of the other Vogtle Owners will have a one-time option at the time the project budget forecast is so revised to tender a portion of its ownership interest to Georgia Power in exchange for Georgia Power's agreement to pay 100% of such Vogtle Owner's remaining share of total construction costs in excess of the EAC in the nineteenth VCM plus $2.1 billion. In this event, Georgia Power will have the option of cancelling the project in lieu of purchasing a portion of the ownership interest of any other Vogtle Owner. If Georgia Power accepts the offer to purchase a portion of another Vogtle Owner's ownership interest in Plant Vogtle Units 3 and 4, the ownership interest(s) to be conveyed from the tendering Vogtle Owner(s) to Georgia Power will be calculated based on the proportion of the cumulative amount of construction costs paid by each such tendering Vogtle Owner(s) and by Georgia Power as of the COD of Plant Vogtle Unit 4. For purposes of this calculation, payments made by Georgia Power on behalf of another Vogtle Owner in accordance with the second and third items described in the paragraph above will be treated as payments made by the applicable Vogtle Owner.

In the event the actual costs of construction at completion of a Unit are less than the EAC reflected in the nineteenth VCM report and such Unit is placed in service in accordance with the schedule projected in the nineteenth VCM report (i.e., Plant Vogtle Unit 3 is placed in service by November 2021 or Plant Vogtle Unit 4 is placed in service by November 2022), Georgia Power will be entitled to 60.7% of the cost savings with respect to the relevant Unit and the remaining Vogtle Owners will be entitled to 39.3% of such savings on a pro rata basis in accordance with their respective ownership interests.

For purposes of the foregoing provisions, qualifying construction costs will not include costs (i) resulting from force majeure events, including governmental actions or inactions (or significant delays associated with issuance of such actions) that affect the licensing, completion, start-up, operations, or financing of Plant Vogtle Units 3 and 4, administrative proceedings or litigation regarding ITAAC or other regulatory challenges to commencement of operation of Plant Vogtle Units 3 and 4, and changes in laws or regulations governing Plant Vogtle Units 3 and 4, (ii) legal fees and legal expenses incurred due to litigation with contractors or subcontractors that are not subsidiaries or affiliates of Southern Company, and (iii) additional costs caused by requests from the Vogtle Owners other than Georgia Power, except for the exercise of a right to vote granted under the Vogtle Joint Ownership Agreements, that increase costs by $100,000 or more.

Pursuant to the Global Amendments, and consistent with the Vogtle Owner Term Sheet, the provisions of the Vogtle Joint Ownership Agreements requiring that Vogtle Owners holding 90% of the ownership interests in Plant Vogtle Units 3 and 4 vote to continue construction following certain adverse events (Project Adverse Events) were also modified. In particular, an increase in the construction cost estimate for Plant Vogtle Units 3 and 4 no longer constitutes a Project Adverse Event and thus would no longer require a vote. In addition, the Project Adverse Event relating to disallowances of cost recovery by Georgia Power now excludes any additional amounts paid by Georgia Power on behalf of the other Vogtle Owners pursuant to the provisions of the Global Amendments described above and the first 6% of costs during any six-month VCM reporting period that are disallowed by the Georgia PSC for recovery, or for which Georgia Power elects not to seek cost recovery, through retail rates. Further, the Global Amendments provide that Georgia Power may cancel the project at any time in its sole discretion.

The Global Amendments provide that if the holders of at least 90% of the ownership interests fail to vote in favor of continuing the project following any future Project Adverse Event, work on Plant Vogtle Units 3 and 4 will continue for a period of 30 days if the holders of more than 50% of the ownership interests vote in favor of continuing construction (Majority Voting Owners). In such a case, the Vogtle Owners (i) have agreed to negotiate in good faith towards the resumption of the project, (ii) if no agreement is reached during such 30-day period, the project will be cancelled, and (iii) in the event of such a cancellation, the Majority Voting Owners will be obligated to reimburse any other Vogtle Owner for the incremental costs it incurred during such 30-day negotiation period.

Purchase of PTCs During Commercial Operation

Pursuant to the Global Amendments, and consistent with the Vogtle Owner Term Sheet, Georgia Power has agreed to purchase additional PTCs from OPC, Dalton, MEAG SPVM, MEAG SPVP, and MEAG SPVJ (to the extent any MEAG SPVJ PTC rights remain after any purchases required under Georgia Power's agreement with MEAG and MEAG SPVJ to provide funding with respect to MEAG SPVJ's ownership interest in Plant Vogtle Units 3 and 4 under certain circumstances) at varying purchase prices dependent upon the actual cost to complete construction of Plant Vogtle Units 3 and 4 as compared to the EAC reflected in the nineteenth VCM report. The purchases are at the option of the applicable Vogtle Owner. The purchases will occur during the month after such PTCs are earned and will be at the following purchase prices: (i) 88% of face value if the actual cost remains at or below the EAC projected in the nineteenth VCM report; (ii) 91% of face value if the actual cost increases by no more than $299 million over the EAC projected in the nineteenth VCM report; (iii) 95% of face value if the actual cost increases at least $300 million but less than $600 million over the EAC in the nineteenth VCM report; and (iv) 98% of face value if the actual cost increases by $600 million or more over the EAC in the nineteenth VCM report.

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 2019 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 are incorporated by reference to the Definitive Information Statement of Alabama Power relating to its 2019 Annual Meeting 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, Mississippi 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, Mississippi 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.

ITEM 14. PRINCIPAL ACCOUNTANT FEES AND SERVICES

The following represents fees billed to Georgia Power, Mississippi Power, Southern Power, and Southern Company Gas in 2018 and 2017 by Deloitte & Touche LLP, each company's principal public accountant:

	2018	2017
	(in thousands)	
Georgia Power		
Audit Fees [1]	$ 3,605	$ 3,247
Audit-Related Fees [2]	31	96
Tax Fees	—	—
All Other Fees [3]	8	1
Total	$ 3,644	$ 3,344
Mississippi Power		
Audit Fees [1]	$ 1,371	$ 1,537
Audit-Related Fees [2]	79	6
Tax Fees	—	—
All Other Fees [3]	—	8
Total	$ 1,450	$ 1,551
Southern Power		
Audit Fees [1]	$ 1,795	$ 1,778
Audit-Related Fees [4]	1,017	439
Tax Fees	—	—
All Other Fees [3]	13	8
Total	$ 2,825	$ 2,225
Southern Company Gas		
Audit Fees [1][5]	$ 3,622	$ 4,449
Audit-Related Fees [6]	520	579
Tax Fees	—	—
All Other Fees [3][7]	7	8
Total	$ 4,149	$ 5,036

(1) Includes services performed in connection with financing transactions.

(2) Represents non-statutory audit services in 2018 and 2017.

(3) Represents registration fees for attendance at Deloitte & Touche LLP-sponsored education seminars.

(4) Represents fees in connection with audits of Southern Power partnerships.

(5) Includes fees in connection with statutory audits of several Southern Company Gas subsidiaries.

(6) Represents fees for non-statutory audit services in 2018 and a review report on internal controls in 2018 and 2017.

(7) Includes subscription fees for Deloitte & Touche LLP's technical accounting research tool in 2017.

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 pre-approval requirements for the audit and non-audit services provided by Deloitte & Touche LLP. All of the services provided by Deloitte & Touche LLP in fiscal years 2018 and 2017 and related fees were approved in advance by the Southern Company 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 Reports on Internal Control Over Financial Reporting for Southern Company and Subsidiary Companies, Alabama Power, Georgia Power, Mississippi Power, Southern Power and Subsidiary Companies, and Southern Company Gas and Subsidiary Companies are listed under Item 9A herein.

Reports of Independent Registered Public Accounting Firm on the financial statements for Southern Company and Subsidiary Companies, Alabama Power Company, Georgia Power Company, Mississippi Power Company, Southern Power Company and Subsidiary Companies, and Southern Company Gas 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, Mississippi Power, Southern Power and Subsidiary Companies, and Southern Company Gas and Subsidiary Companies are listed under Item 8 herein.

Reports of Independent Registered Public Accounting Firm on the financial statement schedules for Southern Company and Subsidiary Companies, Alabama Power Company, Georgia Power Company, Mississippi Power Company, Southern Power Company and Subsidiary Companies, and Southern Company Gas and Subsidiary Companies are listed in the Index to the Financial Statement Schedules at page S-1.

The financial statement schedules for Southern Company and Subsidiary Companies, Alabama Power, Georgia Power, Mississippi Power, Southern Power and Subsidiary Companies, 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, 2018 and 2017 and for the years ended December 31, 2018 and 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, 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.

INDEX TO FINANCIAL STATEMENT SCHEDULES

	Page
Reports of Independent Registered Public Accounting Firm on the Financial Statement Schedules	S-2
Schedule II	
Valuation and Qualifying Accounts and Reserves 2018, 2017, and 2016	
The Southern Company and Subsidiary Companies	S-8
Alabama Power Company	S-9
Georgia Power Company	S-10
Mississippi Power Company	S-11
Southern Power Company and Subsidiary Companies	S-12
Southern Company Gas and Subsidiary Companies	S-13

Schedules I through V not listed above are omitted as not applicable or not required. Columns omitted from schedules filed have been omitted because the information is not applicable or not required.

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 The Southern Company and subsidiary companies (Southern Company) as of December 31, 2018 and 2017, and for each of the three years in the period ended December 31, 2018, and Southern Company's internal control over financial reporting as of December 31, 2018, and have issued our report thereon dated February 19, 2019; such report is included elsewhere in this Form 10-K. Our audits also included the financial statement schedule of Southern Company (Page S-8) listed in the Index at Item 15. This financial statement schedule is the responsibility of Southern 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 19, 2019

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 (Alabama Power) (a wholly-owned subsidiary of The Southern Company) as of December 31, 2018 and 2017, and for each of the three years in the period ended December 31, 2018, and have issued our report thereon dated February 19, 2019; such report is included elsewhere in this Form 10-K. Our audits also included the financial statement schedule of Alabama Power (Page S-9) listed in the Index at Item 15. This financial statement schedule is the responsibility of Alabama Power'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 19, 2019

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 (Georgia Power) (a wholly-owned subsidiary of The Southern Company) as of December 31, 2018 and 2017, and for each of the three years in the period ended December 31, 2018, and have issued our report thereon dated February 19, 2019; such report is included elsewhere in this Form 10-K. Our audits also included the financial statement schedule of Georgia Power (Page S-10) listed in the Index at Item 15. This financial statement schedule is the responsibility of Georgia Power'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 19, 2019

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 (Mississippi Power) (a wholly-owned subsidiary of The Southern Company) as of December 31, 2018 and 2017, and for each of the three years in the period ended December 31, 2018, and have issued our report thereon dated February 19, 2019; such report is included elsewhere in this Form 10-K. Our audits also included the financial statement schedule of Mississippi Power (Page S-11) listed in the Index at Item 15. This financial statement schedule is the responsibility of Mississippi Power'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 19, 2019

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 Statement Schedule

We have audited the consolidated financial statements of Southern Power Company and subsidiary companies (Southern Power) (a wholly-owned subsidiary of The Southern Company) as of December 31, 2018 and 2017, and for each of the three years in the period ended December 31, 2018, and have issued our report thereon dated February 19, 2019; such report is included elsewhere in this Form 10-K. Our audits also included the financial statement schedule of Southern Power (Page S-12) listed in the Index at Item 15. This financial statement schedule is the responsibility of Southern Power'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 19, 2019

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 (Southern Company Gas) (a wholly-owned subsidiary of The Southern Company) as of December 31, 2018 and 2017, and the six-month periods ended June 30, 2016 (Predecessor) and December 31, 2016 (Successor), and have issued our report thereon dated February 19, 2019; 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), Southern Company Gas' investment in which is accounted for by the use of the equity method. Southern Company Gas' financial statements include its equity investment in SNG of $1,261 million and $1,262 million as of December 31, 2018 and December 31, 2017, respectively, and its earnings from its equity method investment in SNG of $131 million, $88 million, and $56 million for the years ended December 31, 2018 and 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 financial statement schedule of Southern Company Gas (Page S-13) listed in the Index at Item 15. This financial statement schedule is the responsibility of Southern Company Gas' 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 19, 2019

THE SOUTHERN COMPANY AND SUBSIDIARY COMPANIES
SCHEDULE II — VALUATION AND QUALIFYING ACCOUNTS
FOR THE YEARS ENDED DECEMBER 31, 2018, 2017, AND 2016
(Stated in Millions of Dollars)

Description	Balance at Beginning of Period	Additions: Charged to Income	Additions: Charged to Other Accounts	Additions: Acquisitions	Deductions	Reclassified to Held for Sale[c]	Balance at End of Period
Provision for uncollectible accounts[a]							
2018	$ 44	$ 69	$ (1)	$ —	$ 61	$ 1	$ 50
2017	43	56	—	—	55	—	44
2016	13	40	(1)	41	50	—	43
Tax valuation allowance (net state)[b]							
2018	$ 148	$ (38)	$ —	$ —	$ 10	$ —	$ 100
2017	22	126	—	—	—	—	148
2016	2	—	—	20	—	—	22

(a) Deductions represent write-offs of accounts considered to be uncollectible, less recoveries of amounts previously written off.

(b) In 2017, Mississippi Power established a valuation allowance for the State of Mississippi net operating loss carryforward expected to expire prior to being fully utilized. This valuation allowance was reduced in 2018 as a result of higher projected state taxable income. In 2018, Georgia Power established a valuation allowance for certain Georgia state tax credits expected to expire prior to being fully utilized, as a result of lower projected state taxable income. See Note 10 to the financial statements in Item 8 herein for additional information.

(c) Represents provision for uncollectible accounts at Gulf Power presented on Southern Company's balance sheet at December 31, 2018 as assets held for sale, current. See Note 15 to the financial statements under "Southern Company's Sale of Gulf Power" and "Assets Held for Sale" in Item 8 herein for additional information.

ALABAMA POWER COMPANY
SCHEDULE II — VALUATION AND QUALIFYING ACCOUNTS
FOR THE YEARS ENDED DECEMBER 31, 2018, 2017, AND 2016
(Stated in Millions of Dollars)

Description	Balance at Beginning of Period	Additions		Deductions[(*)]	Balance at End of Period
		Charged to Income	Charged to Other Accounts		
Provision for uncollectible accounts					
2018	$ 9	$ 13	$ —	$ 12	$ 10
2017	10	10	—	11	9
2016	10	11	—	11	10

(*) Deductions represent write-offs of accounts considered to be uncollectible, less recoveries of amounts previously written off.

GEORGIA POWER COMPANY
SCHEDULE II — VALUATION AND QUALIFYING ACCOUNTS
FOR THE YEARS ENDED DECEMBER 31, 2018, 2017, AND 2016
(Stated in Millions of Dollars)

Description	Balance at Beginning of Period	Additions		Deductions	Balance at End of Period
		Charged to Income	Charged to Other Accounts		
Provision for uncollectible accounts[(a)]					
2018	$ 3	$ 11	$ —	$ 12	$ 2
2017	3	11	—	11	3
2016	2	15	—	14	3
Tax valuation allowance (net state)[(b)]					
2018	$ —	$ 39	$ —	$ 6	$ 33
2017	—	—	—	—	—
2016	—	—	—	—	—

(a) Deductions represent write-offs of accounts considered to be uncollectible, less recoveries of amounts previously written off.

(b) In 2018, Georgia Power established a valuation allowance for certain Georgia state tax credits expected to expire prior to being fully utilized, as a result of lower projected state taxable income. See Note 10 to the financial statements in Item 8 herein for additional information.

MISSISSIPPI POWER COMPANY
SCHEDULE II — VALUATION AND QUALIFYING ACCOUNTS
FOR THE YEARS ENDED DECEMBER 31, 2018, 2017, AND 2016
(Stated in Millions of Dollars)

Description	Balance at Beginning of Period	Additions		Deductions	Balance at End of Period
		Charged to Income	Charged to Other Accounts		
Provision for uncollectible accounts[(a)]					
2018	$ 1	$ 1	$ —	$ 1	$ 1
2017	—	2	—	1	1
2016	—	1	—	1	—
Tax valuation allowance (net state)[(b)]					
2018	$ 124	$ (92)	$ —	$ —	$ 32
2017	—	124	—	—	124
2016	—	—	—	—	—

(a) Deductions represent write-offs of accounts considered to be uncollectible, less recoveries of amounts previously written off.

(b) In 2017, Mississippi Power established a valuation allowance for the State of Mississippi net operating loss carryforward expected to expire prior to being fully utilized. This valuation allowance was reduced in 2018 as a result of higher projected state taxable income. See Note 10 to the financial statements in Item 8 herein for additional information.

SOUTHERN POWER COMPANY AND SUBSIDIARY COMPANIES
SCHEDULE II — VALUATION AND QUALIFYING ACCOUNTS
FOR THE YEARS ENDED DECEMBER 31, 2018, 2017, AND 2016
(Stated in Millions of Dollars)

Description	Balance at Beginning of Period	Additions		Deductions	Balance at End of Period
		Charged to Income	Charged to Other Accounts		
Tax valuation allowance (net state)					
2018	$ 10	$ 12	$ —	$ —	$ 22
2017	—	10	—	—	10
2016	—	—	—	—	—

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 YEARS ENDED DECEMBER 31, 2018 AND 2017
AND THE PREDECESSOR PERIOD OF JANUARY 1, 2016 THROUGH JUNE 30, 2016
(Stated in Millions of Dollars)

Description	Balance at Beginning of Period	Additions		Deductions	Balance at End of Period
		Charged to Income	Charged to Other Accounts		
Successor – December 31, 2018					
Provision for uncollectible accounts(*)	$ 28	$ 33	$ (1)	$ 30	$ 30
Income tax valuation allowance (net state)	11	1	—	—	12
Successor – December 31, 2017					
Provision for uncollectible accounts(*)	$ 27	$ 28	$ —	$ 27	$ 28
Income tax valuation allowance (net state)	19	—	—	8	11
Successor – December 31, 2016					
Provision for uncollectible accounts(*)	$ 38	$ 9	$ (1)	$ 19	$ 27
Income tax valuation allowance (net state)	19	—	—	—	19
Predecessor – June 30, 2016					
Provision for uncollectible accounts(*)	$ 29	$ 16	$ 2	$ 9	$ 38
Income tax valuation allowance (net state)	19	—	—	—	19

(*) Deductions represent write-offs 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.)
	(a)	2	—	Stock Purchase Agreement, dated as of May 20, 2018, by and among Southern Company, 700 Universe, LLC, and NextEra Energy. (Designated in Form 8-K dated May 23, 2018, File No. 1-3526, as Exhibit 2(a)1.)
*	(a)	3	—	Amendment No. 1 to Stock Purchase Agreement, dated as of January 1, 2019, by and among Southern Company, 700 Universe, LLC, and NextEra Energy.**
	(a)	4	—	Stock Purchase Agreement, dated as of May 20, 2018, by and among Southern Company Gas, NUI Corporation, 700 Universe, LLC, and NextEra Energy. (Designated in Form 8-K dated May 23, 2018, File No. 1-3526, as Exhibit 2(a)2.)
	(a)	5	—	Equity Interest Purchase Agreement, dated as of May 20, 2018, by and among Southern Power Company, 700 Universe, LLC, and NextEra Energy. (Designated in Form 8-K dated May 23, 2018, File No. 1-3526, as Exhibit 2(a)3.)

Southern Power

	(e)	1	—	Equity Interest Purchase Agreement, dated as of May 20, 2018, by and among Southern Power Company, 700 Universe, LLC, and NextEra Energy. See Exhibit 2(a)5 herein.

Southern Company Gas

	(f)	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.
	(f)	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.)
	(f)	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	—	Restated Certificate of Incorporation of Southern Company, dated February 12, 2019.
	(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.)

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.)

Mississippi Power

(d)	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.)
(d)	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

(e)	1	—	Certificate of Incorporation of Southern Power Company dated January 8, 2001. (Designated in Registration No. 333-98553 as Exhibit 3.1.)
(e)	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, 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 August 17, 2018. (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), in Form 10-Q for the quarter ended June 30, 2017, File No. 1-3526, as Exhibit 4(a)2, and in Form 10-Q for the quarter ended September 30, 2018, File No. 1-3526, as Exhibit 4(a)1.)

(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 June 28, 2018. (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 March 12, 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 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, in Form 8-K dated November 2, 2017, File No. 1-3164, as Exhibit 4.6, and in Form 8-K dated June 21, 2018, 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.)

Georgia Power

(c)	1	—	Senior Note Indenture dated as of January 1, 1998, between Georgia Power and Wells Fargo Bank, National Association, as Successor Trustee, and certain indentures supplemental thereto through August 8, 2017. (Designated in Form 8-K dated January 21, 1998, File No. 1-6468, as Exhibits 4.1, in Form 8-K dated April 10, 2003, File No. 1-6468, as Exhibit 4.1, in Form 8-K dated March 6, 2007, File No. 1-6468, as Exhibit 4.2, in Form 8-K dated February 4, 2009, File No. 1-6468, as Exhibit 4.2, in Form 8-K dated December 8, 2009, File No. 1-6468, as Exhibit 4.2, in Form 8-K dated May 24, 2010, File No. 1-6468, as Exhibit 4.2, in Form 8-K dated August 26, 2010, File No. 1-6468, as Exhibit 4.2, in Form 8-K dated February 29, 2012, File No. 1-6468, as Exhibit 4.2, in Form 8-K dated May 8, 2012, File No. 1-6468, as Exhibit 4.2(b), in Form 8-K dated March 12, 2013, File No. 1-6468, as Exhibit 4.2(a), in Form 8-K dated March 2, 2016, File No. 1-6468, as Exhibit 4.2(a), in Form 8-K dated March 2, 2016, File No. 1-6468, as Exhibit 4.2(b), in Form 8-K dated February 28, 2017, File No. 1-6468, as Exhibit 4.2(a), in Form 8-K dated February 28, 2017, File No. 1-6468, as Exhibit 4.2(b), and in Form 8-K dated August 3, 2017, File No. 1-6468, as Exhibit 4.2.)
(c)	2	—	Subordinated Note Indenture, dated as of September 1, 2017, between Georgia Power and Wells Fargo Bank, National Association, as Trustee, and First Supplemental Indenture thereto dated as of September 21, 2017. (Designated in Form 8-K dated September 18, 2017, File No. 1-6468, as Exhibit 4.3, and in Form 8-K dated September 18, 2017, File No. 1-6468, as Exhibit 4.4.)
(c)	3	—	Loan Guarantee Agreement between Georgia Power and the DOE dated as of February 20, 2014, Amendment No. 1 thereto dated as of June 4, 2015, Amendment No. 2 thereto dated as of March 9, 2016, Amendment No. 3 thereto dated as of July 27, 2017, and Amendment No. 4 thereto dated as of December 8, 2017. (Designated in Form 8-K dated February 20, 2014, File No. 1-6468, as Exhibit 4.1, in Form 10-Q for the quarter ended June 30, 2015, File No. 1-6468, as Exhibit 10(c)1, in Form 10-Q for the quarter ended March 31, 2016, File No. 1-6468, as Exhibit 4(c)3, in Form 8-K dated July 27, 2017, File No. 1-6468, as Exhibit 4.1, and in Form 8-K dated December 8, 2017, File No. 1-6468, as Exhibit 4.1.)
(c)	4	—	Note Purchase Agreement among Georgia Power, the DOE, and the Federal Financing Bank dated as of February 20, 2014. (Designated in Form 8-K dated February 20, 2014, File No. 1-6468, as Exhibit 4.2.)
(c)	5	—	Future Advance Promissory Note dated February 20, 2014 made by Georgia Power to the FFB. (Designated in Form 8-K dated February 20, 2014, File No. 1-6468, as Exhibit 4.3.)
(c)	6	—	Deed to Secure Debt, Security Agreement and Fixture Filing between Georgia Power and PNC Bank, National Association, doing business as Midland Loan Services Inc., a division of PNC Bank, National Association dated as of February 20, 2014. (Designated in Form 8-K dated February 20, 2014, File No. 1-6468, as Exhibit 4.4.)
(c)	7	—	Owners Consent to Assignment and Direct Agreement and Amendment to Plant Alvin W. Vogtle Additional Units Ownership Participation Agreement by and among Georgia Power, OPC, MEAG Power, and Dalton dated as of February 20, 2014. (Designated in Form 8-K dated February 20, 2014, File No. 1-6468, as Exhibit 4.5.)

Mississippi Power

(d)	1	—	Senior Note Indenture dated as of May 1, 1998, between Mississippi Power and Wells Fargo Bank, National Association, as Successor Trustee, and certain indentures supplemental thereto through March 27, 2018. (Designated in Form 8-K dated May 14, 1998, File No. 001-11229, as Exhibit 4.1, in Form 8-K dated October 11, 2011, File No. 001-11229, as Exhibit 4.2(b), in Form 8-K dated March 5, 2012, File No. 001-11229, as Exhibit 4.2(b), in Form 8-K dated March 22, 2018, File No. 001-11229, as Exhibit 4.2(a) and in Form 8-K dated March 22, 2018, File No. 001-11229, as Exhibit 4.2(b).)

Southern Power

(e)	1	—	Senior Note Indenture dated as of June 1, 2002, between Southern Power Company and Wells Fargo Bank, National Association, as Successor Trustee, and certain indentures supplemental thereto through November 20, 2017. (Designated in Registration No. 333-98553 as Exhibit 4.1, in Form 8-K dated September 14, 2011, File No. 333-98553, as Exhibit 4.4, in Form 8-K dated July 10, 2013, File No. 333-98553, as Exhibit 4.4, in Form 8-K dated May 14, 2015, File No. 333-98553, as Exhibit 4.4(b), in Form 8-K dated November 12, 2015, File No. 333-98553, as Exhibit 4.4(a), in Form 8-K dated June 13, 2016, File No. 001-37803, as Exhibit 4.4(a), in Form 8-K dated June 13, 2016, File No. 001-37803, as Exhibit 4.4(b), in Form 10-Q for the quarter ended September 30, 2016, File No. 001-37803, as Exhibit 4(f)1, in Form 10-Q for the quarter ended September 30, 2016, File No. 001-37803, as Exhibit 4(f)2, in Form 8-K dated November 10, 2016, File No. 001-37803, as Exhibit 4.4(a), in Form 8-K dated November 10, 2016, File No. 001-37803, as Exhibit 4.4(b), in Form 8-K dated November 10, 2016, File No. 001-37803, as Exhibit 4.4(c), and in Form 10-K for the year ended December 31, 2017, File No 001-37803, as Exhibit 4(f)2.)

Southern Company Gas

(f)	1	—	Indenture dated February 20, 2001 between AGL Capital Corporation, AGL Resources Inc., and The Bank of New York, as Trustee. (Designated in Form S-3, File No. 333-69500, as Exhibit 4.2.)
(f)	2	—	Southern Company Gas Capital Corporation's 6.00% Senior Notes due 2034, 5.25% Senior Notes due 2019, Form of 3.50% Senior Notes due 2021, 5.875% Senior Notes due 2041, Form of Series B Senior Notes due 2018, 4.40% Senior Notes due 2043, 3.875% Senior Notes due 2025, 3.250% Senior Notes due 2026, Form of 2.450% Senior Note due October 1, 2023, Form of 3.950% Senior Note due October 1, 2046, and Form of Series 2017A 4.400% Senior Note due May 30, 2047. (Designated in Form 8-K dated September 22, 2004, File No. 1-14174, as Exhibit 4.1, in Form 8-K dated August 5, 2009, File No. 1-14174, as Exhibit 4.1, in Form 8-K dated September 15, 2011, File No. 1-14174, as Exhibit 4.1, in Form 8-K dated March 16, 2011, File No. 1-14174, as Exhibit 4.1, in Form 8-K dated August 31, 2011, File No. 1-14174, as Exhibit 4.2, in Form 8-K dated May 13, 2013, File No. 1-14174, as Exhibit 4.2, in Form 8-K dated November 13, 2015, File No. 1-14174, as Exhibit 4.2, in Form 8-K dated May 13, 2016, File No. 1-14174, as Exhibit 4.2, in Form 8-K dated September 8, 2016, File No. 1-14174, as Exhibit 4.1(a), in Form 8-K dated September 8, 2016, File No. 1-14174, as Exhibit 4.1(b), and in Form 8-K dated May 5, 2017, File No. 1-14174, as Exhibit 4.1, respectively.)
(f)	3	—	Southern Company Gas' Guarantee related to the 6.00% Senior Notes due 2034, Guarantee related to the 5.25% Senior Notes due 2019, Guarantee related to the 5.875% Senior Notes due 2041, Form of Guarantee related to the 3.50% Senior Notes due 2021, Guarantee related to the 4.40% Senior Notes due 2043, Guarantee related to the 3.875% Senior Notes due 2025, Guarantee related to the 3.250% Senior Notes due 2026, Form of Guarantee related to the 2.450% Senior Notes due October 1, 2023, Form of Guarantee related to the 3.950% Senior Notes due October 1, 2046, and Form of Guarantee related to the Series 2017A 4.400% Senior Notes due May 30, 2047. (Designated in Form 8-K dated September 22, 2004, File No. 1-14174, as Exhibit 4.3, in Form 8-K dated March 16, 2011, File No. 1-14174, as Exhibit 4.2, in Form 8-K dated September 15, 2011, File No. 1-14174, as Exhibit 4.2, in Form 8-K dated May 13, 2013, File No. 1-14174, as Exhibit 4.3, in Form 8-K dated November 13, 2015, File No. 1-14174, as Exhibit 4.3, in Form 8-K dated May 13, 2016, File No. 1-14174, as Exhibit 4.3, in Form 8-K dated September 8, 2016, File No. 1-14174, as Exhibit 4.3(a), in Form 8-K dated September 8, 2016, File No. 1-14174, as Exhibit 4.3(b), and in Form 8-K dated May 5, 2017, File No. 1-14174, as Exhibit 4.3, respectively.)
(f)	4	—	Indenture dated December 1, 1989 of Atlanta Gas Light Company and First Supplemental Indenture thereto dated March 16, 1992. (Designated in Form S-3, File No. 33-32274, as Exhibit 4(a) and in Form S-3, File No. 33-46419, as Exhibit 4(a).)

	(f)	5	—	Indenture of Commonwealth Edison Company to Continental Illinois National Bank and Trust Company of Chicago, Trustee, dated as of January 1, 1954, Indenture of Adoption of Northern Illinois Gas Company to Continental Illinois National Bank and Trust Company of Chicago, Trustee, dated February 9, 1954, and certain indentures supplemental thereto. (Designated in Form 10-K for the year ended December 31, 1995, File No. 1-7296, as Exhibit 4.01, in Form 10-K for the year ended December 31, 1995, File No. 1-7296, as Exhibit 4.02, in Registration No. 2-56578 as Exhibits 2.21 and 2.25, in Form 10-Q for the quarter ended June 30, 1996, File No. 1-7296, as Exhibit 4.01, in Form 10-K for the year ended December 31, 1997, File No. 1-7296, as Exhibit 4.19, in Form 10-K for the year ended December 31, 2003, File No. 1-7296, as Exhibit 4.09, in Form 10-K for the year ended December 31, 2003, File No. 1-7296, as Exhibit 4.10, in Form 10-K for the year ended December 31, 2003, File No. 1-7296, as Exhibit 4.11, in Form 10-K for the year ended December 31, 2006, File No. 1-7296, as Exhibit 4.11, in Form 10-Q for the quarter ended September 30, 2008, File No. 1-7296, as Exhibit 4.01, in Form 10-Q for the quarter ended June 31, 2009, File No. 1-7296, as Exhibit 4.01, in Form 10-Q for the quarter ended September 30, 2012, File No. 1-7296, as Exhibit 4, in Form 10-K for the year ended December 31, 2016, File No. 1-14174, as Exhibit 4(g)6, in Form 10-K for the year ended December 31, 2017, File No. 1-14174, as Exhibit 4(g)6, and in Form 10-Q for the quarter ended September 30, 2018, File No. 1-14174, as Exhibit 4(g)1.)

(10) Material Contracts

Southern Company

#	(a)	1	—	Southern Company 2011 Omnibus Incentive Compensation Plan effective May 25, 2011. (Designated in Form 8-K dated May 25, 2011, File No. 1-3526, as Exhibit 10.1.)
#	(a)	2	—	Form of Stock Option Award Agreement for Executive Officers of Southern Company under the Southern Company Omnibus Incentive Compensation Plan. (Designated in Form 10-Q for the quarter ended March 31, 2011, File No. 1-3526, as Exhibit 10(a)3.)
#	(a)	3	—	Deferred Compensation Plan for Outside Directors of The Southern Company, Amended and Restated effective January 1, 2008 and First Amendment thereto effective April 1, 2015. (Designated in Form 10-K for the year ended December 31, 2007, File No. 1-3526, as Exhibit 10(a)3 and in Form 10-Q for the quarter ended June 30, 2015, File No. 1-3526, as Exhibit 10(a)2.)
#	(a)	4	—	Southern Company Deferred Compensation Plan, Amended and Restated as of January 1, 2018. (Designated in Form 10-K for the year ended December 31, 2017, File No. 1-3536, as Exhibit 10(a)4.)
#	(a)	5	—	The Southern Company Supplemental Executive Retirement Plan, Amended and Restated effective June 30, 2016, Amendment No. 1 thereto effective January 1, 2017, Amendment No. 2 thereto effective January 1, 2018, and Amendment No. 3 thereto effective April 1, 2018. (Designated in Form 10-Q for the quarter ended June 30, 2016, File No. 1-3526, as Exhibit 10(a)1, in Form 10-K for the year ended December 31, 2016, File No. 1-3536, as Exhibit 10(a)18, in Form 10-K for the year ended December 31, 2017, File No. 1-3526, as Exhibit 10(a)16, and in Form 10-Q for the quarter ended March 31, 2018, File No. 1-3526, as Exhibit 10(a)1.)
#	(a)	6	—	The Southern Company Supplemental Benefit Plan, Amended and Restated effective as of June 30, 2016, Amendment No. 1 thereto effective January 1, 2017, Amendment No. 2 thereto effective January 1, 2018, and Amendment No. 3 thereto effective April 1, 2018. (Designated in Form 10-Q for the quarter ended June 30, 2016, File No. 1-3526, as Exhibit 10(a)2, in Form 10-K for the year ended December 31, 2016, File No. 1-3536, as Exhibit 10(a)19, in Form 10-K for the year ended December 31, 2017, File No. 1-3526, as Exhibit 10(a)17, and in Form 10-Q for the quarter ended March 31, 2018, File No. 1-3526, as Exhibit 10(a)2.)
#	(a)	7	—	The Southern Company Change in Control Benefits Protection Plan (an amendment and restatement of The Southern Company Change in Control Benefit Plan Determination Policy), effective December 31, 2008 and Amendment No. 1 thereto effective March 1, 2018. (Designated in Form 8-K dated December 31, 2008, File No. 1-3526, as Exhibit 10.1 and in Form 10-Q for the quarter ended March 31, 2018, File No. 1-3526, as Exhibit 10(a)3.)

#		(a)	8	—	Deferred Compensation Trust Agreement for Directors of Southern Company and its Subsidiaries, Amended and Restated effective January 1, 2001, between Wells Fargo Bank, N.A., as successor to Wachovia Bank, N.A., Southern Company, SCS, Alabama Power, Georgia Power, Mississippi Power, Southern Linc, Southern Company Energy Solutions, LLC, and Southern Nuclear and First Amendment thereto effective January 1, 2009. (Designated in Form 10-K for the year ended December 31, 2000, File No. 1-3526, as Exhibit 10(a)103 and in Form 10-K for the year ended December 31, 2008, File No. 1-3526, as Exhibit 10(a)16.)
#		(a)	9	—	Deferred Stock Trust Agreement for Directors of Southern Company and its Subsidiaries, Amended and Restated effective January 1, 2000, between Reliance Trust Company, Southern Company, Alabama Power, Georgia Power, and Mississippi Power and First Amendment thereto effective January 1, 2009. (Designated in Form 10-K for the year ended December 31, 2000, File No. 1-3526, as Exhibit 10(a)104 and in Form 10-K for the year ended December 31, 2008, File No. 1-3526, as Exhibit 10(a)18.)
#		(a)	10	—	Deferred Cash Compensation Trust Agreement for Directors of Southern Company and its Subsidiaries, Amended and Restated effective September 1, 2001, between Wells Fargo Bank, N.A., as successor to Wachovia Bank, N.A., Southern Company, Alabama Power, Georgia Power, and Mississippi Power and First Amendment thereto effective January 1, 2009. (Designated in Form 10-K for the year ended December 31, 2001, File No. 1-3526, as Exhibit 10(a)92 and in Form 10-K for the year ended December 31, 2008, File No. 1-3526, as Exhibit 10(a)20.)
#		(a)	11	—	Southern Company Senior Executive Change in Control Severance Plan, Amended and Restated effective December 31, 2008, First Amendment thereto effective October 19, 2009, and Second Amendment thereto effective February 22, 2011. (Designated in Form 10-K for the year ended December 31, 2008, File No. 1-3526, as Exhibit 10(a)23, in Form 10-K for the year ended December 31, 2009, File No. 1-3526, as Exhibit 10(a)22, and in Form 10-K for the year ended December 31, 2010, File No. 1-3526, as Exhibit 10(a)16.)
#		(a)	12	—	Southern Company Executive Change in Control Severance Plan, Amended and Restated effective December 31, 2008 and First Amendment thereto effective January 1, 2010. (Designated in Form 10-K for the year ended December 31, 2008, File No. 1-3526, as Exhibit 10(a)24 and in Form 10-K for the year ended December 31, 2009, File No. 1-3526, as Exhibit 10(a)24.)
#		(a)	13	—	Form of Terms for Performance Share Awards granted under the Southern Company 2011 Omnibus Incentive Compensation Plan. (Designated in Form 10-Q for the quarter ended March 31, 2017, File No. 1-3526, as Exhibit 10(a)1).
#		(a)	14	—	Outside Directors Stock Plan for The Southern Company and its Subsidiaries effective June 1, 2015. (Designated in Definitive Proxy Statement filed April 10, 2015, File No. 1-3526, as Appendix A.)
#		(a)	15	—	Deferred Compensation Agreement between Southern Company, SCS, Alabama Power, and Mark A. Crosswhite, effective July 30, 2008. (Designated in Form 10-K for the year ended December 31, 2016, File No. 1-3526, as Exhibit 10(a)17.)
		(a)	16	—	The Southern Company Employee Savings Plan, Amended and Restated effective January 1, 2018. (Designated in Post-Effective Amendment No. 1 to Form S-8, File No. 333-212783 as Exhibit 4.3.)
#		(a)	17	—	Form of Terms for Restricted Stock Unit with Performance Measure Awards granted under the Southern Company 2011 Omnibus Incentive Compensation Plan. (Designated in Form 10-Q for the quarter ended March 31, 2017, File No. 1-3526, as Exhibit 10(a)2.)
#		(a)	18	—	Letter Agreement among Southern Company Gas, Southern Company, and Andrew W. Evans and Performance Stock Unit Award Agreement, dated September 29, 2016. (Designated in Form 10-Q for the quarter ended March 31, 2017, File No. 1-3526, as Exhibit 10(a)3.)
#		(a)	19	—	Form of Time-Vesting Restricted Stock Unit Awards granted under the Southern Company 2011 Omnibus Incentive Compensation Plan. (Designated in Form 10-Q for the quarter ended March 31, 2017, File No. 1-3526, as Exhibit 10(a)4.)
#		(a)	20	—	Consulting Agreement between SCS and Arthur P. Beattie effective August 1, 2018. (Designated in Form 10-Q for the quarter ended June 30, 2018, File No. 1-3526, as Exhibit 10(a)1.)
#	*	(a)	21	—	First Amendment to the Southern Company Deferred Compensation Plan, dated December 7, 2018.
#	*	(a)	22	—	Second Amendment to the Southern Company Deferred Compensation Plan, dated January 29, 2019.

#	*	(a)	23	—	Fourth Amendment to the Southern Company Supplemental Executive Retirement Plan, dated December 7, 2018.
#	*	(a)	24	—	Fifth Amendment to the Southern Company Supplemental Executive Retirement Plan, dated January 29, 2019.
#	*	(a)	25	—	Fourth Amendment to the Southern Company Supplemental Benefit Plan, dated December 14, 2018.
#	*	(a)	26	—	Fifth Amendment to the Southern Company Supplemental Benefit Plan, dated January 29, 2019.
#	*	(a)	27	—	Second Amendment to the Deferred Stock Trust Agreement For Directors of Southern Company and Its Subsidiaries, dated December 29, 2018.
#	*	(a)	28	—	Second Amendment to the Deferred Cash Compensation Trust Agreement For Directors of Southern Company and Its Subsidiaries, dated December 21, 2018.

Alabama Power

		(b)	1	—	Intercompany Interchange Contract as revised effective May 1, 2007, among Alabama Power, Georgia Power, Gulf Power, Mississippi Power, Southern Power Company, and SCS. (Designated in Form 10-Q for the quarter ended March 31, 2007, File No. 1-3164, as Exhibit 10(b)5.)
	*	(b)	2	—	Appendix A to the Southern Company System Intercompany Interchange Contract, dated as of January 1, 2019.
#		(b)	3	—	Southern Company 2011 Omnibus Incentive Compensation Plan effective May 25, 2011. See Exhibit 10(a)1 herein.
#		(b)	4	—	Form of Stock Option Award Agreement for Executive Officers of Southern Company under the Southern Company Omnibus Incentive Compensation Plan. See Exhibit 10(a)2 herein.
#		(b)	5	—	Southern Company Deferred Compensation Plan, Amended and Restated as of January 1, 2018. See Exhibit 10(a)4 herein.
#		(b)	6	—	The Southern Company Supplemental Executive Retirement Plan, Amended and Restated effective June 30, 2016 and Amendment No. 1 thereto effective January 1, 2017. See Exhibit 10(a)5 herein.
#		(b)	7	—	The Southern Company Supplemental Benefit Plan, Amended and Restated effective as of June 30, 2016 and Amendment No. 1 thereto effective January 1, 2017. See Exhibit 10(a)6 herein.
#		(b)	8	—	Southern Company Executive Change in Control Severance Plan, Amended and Restated effective December 31, 2008 and First Amendment thereto effective January 1, 2010. See Exhibit 10(a)12 herein.
#		(b)	9	—	Deferred Compensation Plan for Outside Directors of Alabama Power Company, Amended and Restated effective January 1, 2008 and First Amendment thereto effective June 1, 2015. (Designated in Form 10-Q for the quarter ended June 30, 2008, File No. 1-3164, as Exhibit 10(b)1 and in Form 10-Q for the quarter ended June 30, 2015, File No. 1-3164, as Exhibit 10(b)1.)
#		(b)	10	—	The Southern Company Change in Control Benefits Protection Plan (an amendment and restatement of The Southern Company Change in Control Benefit Plan Determination Policy), effective December 31, 2008. See Exhibit 10(a)7 herein.
#		(b)	11	—	Deferred Compensation Trust Agreement for Directors of Southern Company and its Subsidiaries, Amended and Restated effective January 1, 2001, between Wells Fargo Bank, N.A., as successor to Wachovia Bank, N.A., Southern Company, SCS, Alabama Power, Georgia Power, Mississippi Power, Southern Linc, Southern Company Energy Solutions, LLC, and Southern Nuclear and First Amendment thereto effective January 1, 2009. See Exhibit 10(a)8 herein.
#		(b)	12	—	Deferred Stock Trust Agreement for Directors of Southern Company and its Subsidiaries, Amended and Restated effective January 1, 2000, between Reliance Trust Company, Southern Company, Alabama Power, Georgia Power, and Mississippi Power and First Amendment thereto effective January 1, 2009. See Exhibit 10(a)9 herein.
#		(b)	13	—	Deferred Cash Compensation Trust Agreement for Directors of Southern Company and its Subsidiaries, Amended and Restated effective September 1, 2001, between Wells Fargo Bank, N.A., as successor to Wachovia Bank, N.A., Southern Company, Alabama Power, Georgia Power, and Mississippi Power and First Amendment thereto effective January 1, 2009. See Exhibit 10(a)10 herein.

#	(b)	14	—	Southern Company Senior Executive Change in Control Severance Plan, Amended and Restated effective December 31, 2008, First Amendment thereto effective October 19, 2009, and Second Amendment thereto effective February 22, 2011. See Exhibit 10(a)11 herein.
#	(b)	15	—	Form of Terms for Performance Share Awards granted under the Southern Company 2011 Omnibus Incentive Compensation Plan. See Exhibit 10(a)13 herein.
#	(b)	16	—	Deferred Compensation Agreement between Southern Company, Alabama Power, Georgia Power, Mississippi Power, and SCS and Philip C. Raymond dated September 15, 2010. (Designated in Form 10-Q for the quarter ended September 30, 2010, File No. 1-3164, as Exhibit 10(b)2.)
#	(b)	17	—	Deferred Compensation Agreement between Southern Company, SCS, Alabama Power, and Mark A. Crosswhite, effective July 30, 2008. See Exhibit 10(a)15 herein.
#	(b)	18	—	Outside Directors Stock Plan for The Southern Company and its Subsidiaries effective June 1, 2015. See Exhibit 10(a)14 herein.
#	(b)	19	—	Form of Terms for Restricted Stock Unit with Performance Measure Awards granted under the Southern Company 2011 Omnibus Incentive Compensation Plan. See Exhibit 10(a)17 herein.
#	(b)	20	—	Form of Time-Vesting Restricted Stock Unit Awards granted under the Southern Company 2011 Omnibus Incentive Compensation Plan. See Exhibit 10(a)19 herein.
#	(b)	21	—	First Amendment to the Southern Company Deferred Compensation Plan, dated December 7, 2018. See Exhibit 10(a)21 herein.
#	(b)	22	—	Second Amendment to the Southern Company Deferred Compensation Plan, dated January 29, 2019. See Exhibit 10(a)22 herein.
#	(b)	23	—	Fourth Amendment to the Southern Company Supplemental Executive Retirement Plan, dated December 7, 2018. See Exhibit 10(a)23 herein.
#	(b)	24	—	Fifth Amendment to the Southern Company Supplemental Executive Retirement Plan, dated January 29, 2019. (See Exhibit 10(a)24 herein.
#	(b)	25	—	Fourth Amendment to the Southern Company Supplemental Benefit Plan, dated December 14, 2018. See Exhibit 10(a)25 herein.
#	(b)	26	—	Fifth Amendment to the Southern Company Supplemental Benefit Plan, dated January 29, 2019. See Exhibit 10(a)26 herein.
#	(b)	27	—	Second Amendment to the Deferred Stock Trust Agreement For Directors of Southern Company and Its Subsidiaries, dated December 29, 2018. See Exhibit 10(a)27 herein.
#	(b)	28	—	Second Amendment to the Deferred Cash Compensation Trust Agreement For Directors of Southern Company and Its Subsidiaries, dated December 21, 2018. See Exhibit 10(a)28 herein.
Georgia Power				
	(c)	1	—	Intercompany Interchange Contract as revised effective May 1, 2007, among Alabama Power, Georgia Power, Gulf Power, Mississippi Power, Southern Power Company, and SCS. See Exhibit 10(b)1 herein.
	(c)	2	—	Appendix A to the Southern Company System Intercompany Interchange Contract, dated as of January 1, 2019. See Exhibit 10(b)2 herein.
	(c)	3	—	Revised and Restated Integrated Transmission System Agreement dated as of November 12, 1990, between Georgia Power and OPC. (Designated in Form 10-K for the year ended December 31, 1990, File No. 1-6468, as Exhibit 10(g).)
	(c)	4	—	Revised and Restated Integrated Transmission System Agreement between Georgia Power and Dalton dated as of December 7, 1990. (Designated in Form 10-K for the year ended December 31, 1990, File No. 1-6468, as Exhibit 10(gg).)
	(c)	5	—	Revised and Restated Integrated Transmission System Agreement between Georgia Power and MEAG dated as of December 7, 1990. (Designated in Form 10-K for the year ended December 31, 1990, File No. 1-6468, as Exhibit 10(hh).)

	(c)	6	—	Interim Assessment Agreement dated as of March 29, 2017, by and among Georgia Power, for itself and as agent for OPC, MEAG, and Dalton, and Westinghouse, WECTEC Staffing Services LLC, and WECTEC Global Project Services, Inc., Amendment 1 thereto dated as of April 28, 2017, Amendment 2 thereto dated as of May 12, 2017, Amendment 3 thereto dated as of June 3, 2017, Amendment 4 thereto dated as of June 5, 2017, Amendment 5 thereto dated as of March 29, 2017, Amendment 6 thereto dated as of June 22, 2017, Amendment 7 thereto dated as of June 28, 2017 and Amendment 8 thereto dated as of July 20, 2017. (Designated in Form 10-Q for the quarter ended March 31, 2017, File No. 1-6468, as Exhibit 10(c)3, in Form 10-Q for the quarter ended March 31, 2017, File No. 1-6468, as Exhibit 10(c)4, in Form 8-K dated May 12, 2017, File No. 1-6468, as Exhibit 10.1, in Form 8-K dated June 3, 2017, File No. 1-6468, as Exhibit 10.1, in Form 8-K dated June 5, 2017, File No. 1-6468, as Exhibit 10.1, in Form 8-K dated June 16, 2017, File No. 1-6468, as Exhibit 10.2, in Form 8-K dated June 22, 2017, File No. 1-6468, as Exhibit 10.1, in Form 8-K dated June 28, 2017, File No. 1-6468, as Exhibit 10.1, and in Form 8-K dated July 20, 2017, File No. 1-6468, as Exhibit 10.1.)
	(c)	7	—	Settlement Agreement dated as of June 9, 2017, by and among Georgia Power, OPC, MEAG, Dalton, and Toshiba and Amendment No. 1 thereto dated as of December 8, 2017. (Designated in Form 8-K dated June 16, 2017, File No. 1-6468, as Exhibit 10.1 and in Form 8-K dated December 8, 2017, File No. 1-6468, as Exhibit 10.1.)
	(c)	8	—	Amended and Restated Services Agreement dated as of June 20, 2017, by and among Georgia Power, for itself and as agent for OPC, MEAG, MEAG Power SPVJ, LLC, MEAG Power SPVM, LLC, MEAG Power SPVP, LLC, and Dalton, and Westinghouse and WECTEC Global Project Services, Inc. (Georgia Power requested confidential treatment for certain portions of this document pursuant to an application for confidential treatment sent to the SEC. Georgia Power omitted such portions from the filing and filed them separately with the SEC.) (Designated in Form 10-Q for the quarter ended June 30, 2017, File No. 1-6468, as Exhibit 10(c)9.)
	(c)	9	—	Construction Completion Agreement dated as of October 23, 2017, between Georgia Power, for itself and as agent for OPC, MEAG, MEAG Power SPVJ, LLC, MEAG Power SPVM, LLC, MEAG Power SPVP, LLC, and Dalton, and Bechtel. (Georgia Power has requested confidential treatment for certain portions of this document pursuant to an application for confidential treatment sent to the SEC. Georgia Power omitted such portions from the filing and filed them separately with the SEC.) (Designated in Form 10-K for the year ended December 31, 2017, File No. 1-6468, as Exhibit 10(c)8.)
*	(c)	10	—	Amendment No. 1 to Construction Completion Agreement dated as of October 12, 2018, between Georgia Power, for itself and as agent for OPC, MEAG, MEAG Power SPVJ, LLC, MEAG Power SPVM, LLC, MEAG Power SPVP, LLC, and Dalton, and Bechtel. (Georgia Power has requested confidential treatment for certain portions of this document pursuant to an application for confidential treatment sent to the SEC. Georgia Power omitted such portions from the filing and filed them separately with the SEC.)
	(c)	11	—	Plant Alvin W. Vogtle Additional Units Ownership Participation Agreement dated as of April 21, 2006, among Georgia Power, OPC, MEAG, and The City of Dalton, Georgia, Amendment 1 thereto dated as of April 8, 2008, Amendment 2 thereto dated as of February 20, 2014, Agreement Regarding Additional Participating Party Rights and Amendment 3 thereto dated as of November 2, 2017, and First Amendment to Agreement Regarding Additional Participating Party Rights and Amendment No. 3 to Plant Alvin W. Vogtle Additional Units Ownership Participation Agreement, dated as of August 31, 2018. (Designated in Form 8-K dated April 21, 2006, File No. 33-7591, as Exhibit 10.4.4, in Form 10-K for the year ended December 31, 2013, File No. 000-53908, as Exhibit 10.3.2(a), in Form 10-K for the year ended December 31, 2013, File No. 000-53908, as Exhibit 10.3.2(b), in Form 10-Q for the quarter ended September 30, 2017, File No. 000-53908, as Exhibit 10.1, and in Form 8-K dated August 31, 2018, File No. 1-6468, as Exhibit 10.1.)
*	(c)	12	—	Global Amendments to Vogtle Additional Units Agreements, dated as of February 18, 2019, among Georgia Power, OPC, MEAG, MEAG Power SPVJ, LLC, MEAG Power SPVM, LLC, MEAG Power SPVP, LLC, and Dalton.
Mississippi Power				
	(d)	1	—	Intercompany Interchange Contract as revised effective May 1, 2007, among Alabama Power, Georgia Power, Gulf Power, Mississippi Power, Southern Power Company, and SCS. See Exhibit 10(b)1 herein.
	(d)	2	—	Appendix A to the Southern Company System Intercompany Interchange Contract, dated as of January 1, 2019. See Exhibit 10(b)2 herein.

(d) 3 — Transmission Facilities Agreement dated February 25, 1982, Amendment No. 1 dated May 12, 1982 and Amendment No. 2 dated December 6, 1983, between Entergy Corporation (formerly Gulf States) and Mississippi Power. (Designated in Form 10-K for the year ended December 31, 1981, File No. 001-11229, as Exhibit 10(f), in Form 10-K for the year ended December 31, 1982, File No. 001-11229, as Exhibit 10(f)(2), and in Form 10-K for the year ended December 31, 1983, File No. 001-11229, as Exhibit 10(f)(3).)

(d) 4 — Cooperative Agreement between the DOE and SCS dated as of December 12, 2008. (Designated in Form 10-K for the year ended December 31, 2008, File No. 001-11229, as Exhibit 10(e)22.) (Mississippi Power requested confidential treatment for certain portions of this document pursuant to an application for confidential treatment sent to the SEC. Mississippi Power omitted such portions from this filing and filed them separately with the SEC.)

Southern Power

(e) 1 — Intercompany Interchange Contract as revised effective May 1, 2007, among Alabama Power, Georgia Power, Gulf Power, Mississippi Power, Southern Power Company, and SCS. See Exhibit 10(b)1 herein.

(e) 2 — Appendix A to the Southern Company System Intercompany Interchange Contract, dated as of January 1, 2019. See Exhibit 10(b)2 herein.

Southern Company Gas

(f) 1 — Final Allocation Agreement dated January 3, 2008. (Designated in Form 10-K for the year ended December 31, 2007, File No. 1-7296, as Exhibit 10.15.)

(f) 2 — Asset Purchase Agreement, dated as of October 15, 2017, by and between Pivotal Utility Holdings, Inc., as Seller, and South Jersey Industries, Inc., as Buyer. (Designated in Form 8-K dated October 15, 2017, File No. 1-14174, as Exhibit 10.1.)

(14) Code of Ethics

Southern Company

(a) — The Southern Company Code of Ethics. (Designated in Form 10-K for the year ended December 31, 2016, File No. 1-3526, as Exhibit 14(a).)

Alabama Power

(b) — The Southern Company Code of Ethics. See Exhibit 14(a) herein.

Georgia Power

(c) — The Southern Company Code of Ethics. See Exhibit 14(a) herein.

Mississippi Power

(d) — The Southern Company Code of Ethics. See Exhibit 14(a) herein.

Southern Power

(e) — The Southern Company Code of Ethics. See Exhibit 14(a) herein.

Southern Company Gas

(f) — The Southern Company Code of Ethics. See Exhibit 14(a) herein.

(21) Subsidiaries of Registrants

Southern Company

* (a) — Subsidiaries of Registrant.

Alabama Power

(b) — Subsidiaries of Registrant. See Exhibit 21(a) herein.

Georgia Power

Omitted pursuant to General Instruction I(2)(b) of Form 10-K.

Mississippi Power

Omitted pursuant to General Instruction I(2)(b) of Form 10-K.

Southern Power

Omitted pursuant to General Instruction I(2)(b) of Form 10-K.

Southern Company Gas

Omitted pursuant to General Instruction I(2)(b) of Form 10-K

(23) Consents of Experts and Counsel

Southern Company

* (a) 1 — Consent of Deloitte & Touche LLP.

Alabama Power

* (b) 1 — Consent of Deloitte & Touche LLP.

Georgia Power

* (c) 1 — Consent of Deloitte & Touche LLP.

Mississippi Power

* (d) 1 — Consent of Deloitte & Touche LLP.

Southern Power

* (e) 1 — Consent of Deloitte & Touche LLP.

Southern Company Gas

* (f) 1 — Consent of Deloitte & Touche LLP.

* (f) 2 — Consent of PricewaterhouseCoopers LLP.

* (f) 3 — Consent of BDO USA, LLP.

(24) Powers of Attorney and Resolutions

Southern Company

* (a) 1 — Power of Attorney and resolution.

* (a) 2 — Power of Attorney of Janaki Akella and Anthony F. Earley, Jr.

Alabama Power

* (b) — Power of Attorney and resolution.

Georgia Power

* (c) — Power of Attorney and resolution.

Mississippi Power

* (d) — Power of Attorney and resolution.

Southern Power

* (e) 1 — Power of Attorney and resolution.

* (e) 2 — Power of Attorney for Stan W. Connally.

Southern Company Gas

* (f) 1 — Power of Attorney and resolution.

* (f) 2 — Power of Attorney of Daniel S. Tucker.

(31) Section 302 Certifications

Southern Company

* (a) 1 — Certificate of Southern Company's Chief Executive Officer required by Section 302 of the Sarbanes-Oxley Act of 2002.

* (a) 2 — Certificate of Southern Company's Chief Financial Officer required by Section 302 of the Sarbanes-Oxley Act of 2002.

Alabama Power

* (b) 1 — Certificate of Alabama Power's Chief Executive Officer required by Section 302 of the Sarbanes-Oxley Act of 2002.

* (b) 2 — Certificate of Alabama Power's Chief Financial Officer required by Section 302 of the Sarbanes-Oxley Act of 2002.

Georgia Power

* (c) 1 — Certificate of Georgia Power's Chief Executive Officer required by Section 302 of the Sarbanes-Oxley Act of 2002.

* (c) 2 — Certificate of Georgia Power's Chief Financial Officer required by Section 302 of the Sarbanes-Oxley Act of 2002.

Mississippi Power

*	(d)	1	—	Certificate of Mississippi Power's Chief Executive Officer required by Section 302 of the Sarbanes-Oxley Act of 2002.
*	(d)	2	—	Certificate of Mississippi Power's Chief Financial Officer required by Section 302 of the Sarbanes-Oxley Act of 2002.

Southern Power

*	(e)	1	—	Certificate of Southern Power Company's Chief Executive Officer required by Section 302 of the Sarbanes-Oxley Act of 2002.
*	(e)	2	—	Certificate of Southern Power Company's Chief Financial Officer required by Section 302 of the Sarbanes-Oxley Act of 2002.

Southern Company Gas

*	(f)	1	—	Certificate of Southern Company Gas' Chief Executive Officer required by Section 302 of the Sarbanes-Oxley Act of 2002.
*	(f)	2	—	Certificate of Southern Company Gas' Chief Financial Officer required by Section 302 of the Sarbanes-Oxley Act of 2002.

(32) Section 906 Certifications

Southern Company

*	(a)	—	Certificate of Southern Company's Chief Executive Officer and Chief Financial Officer required by Section 906 of the Sarbanes-Oxley Act of 2002.

Alabama Power

*	(b)	—	Certificate of Alabama Power's Chief Executive Officer and Chief Financial Officer required by Section 906 of the Sarbanes-Oxley Act of 2002.

Georgia Power

*	(c)	—	Certificate of Georgia Power's Chief Executive Officer and Chief Financial Officer required by Section 906 of the Sarbanes-Oxley Act of 2002.

Mississippi Power

*	(d)	—	Certificate of Mississippi Power's Chief Executive Officer and Chief Financial Officer required by Section 906 of the Sarbanes-Oxley Act of 2002.

Southern Power

*	(e)	—	Certificate of Southern Power Company's Chief Executive Officer and Chief Financial Officer required by Section 906 of the Sarbanes-Oxley Act of 2002.

Southern Company Gas

*	(f)	—	Certificate of Southern Company Gas' Chief Executive Officer and Chief Financial Officer required by Section 906 of the Sarbanes-Oxley Act of 2002.

(99) Additional Exhibits

Southern Company Gas

*	(f)	—	The financial statements of Southern Natural Gas Company, L.L.C., pursuant to Rule 3-09 of Regulation S-X.

(101) XBRL-Related Documents

*	INS	— XBRL Instance Document
*	SCH	— XBRL Taxonomy Extension Schema Document
*	CAL	— XBRL Taxonomy Calculation Linkbase Document
*	DEF	— XBRL Definition Linkbase Document
*	LAB	— XBRL Taxonomy Label Linkbase Document
*	PRE	— XBRL Taxonomy Presentation Linkbase Document

** Schedules and exhibits have been omitted pursuant to Item 601(b)(2) of Regulation S-K. A copy of any omitted schedule or exhibit will be furnished supplementally to the Securities and Exchange Commission upon request; provided, however, that each registrant may request confidential treatment pursuant to Rule 24b-2 of the Securities Exchange Act of 1934, as amended, for any schedules or exhibits so furnished.

THE SOUTHERN COMPANY

SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized. The signature of the undersigned company shall be deemed to relate only to matters having reference to such company and any subsidiaries thereof.

THE SOUTHERN COMPANY

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

By: /s/Melissa K. Caen
(Melissa K. Caen, Attorney-in-fact)

Date: February 19, 2019

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed below by the following persons on behalf of the registrant and in the capacities and on the dates indicated. The signature of each of the undersigned shall be deemed to relate only to matters having reference to the above-named company and any subsidiaries thereof.

Thomas A. Fanning
Chairman, President, and
Chief Executive Officer
(Principal Executive Officer)

Andrew W. Evans
Executive Vice President and Chief Financial Officer
(Principal Financial Officer)

Ann P. Daiss
Comptroller and Chief Accounting Officer
(Principal Accounting Officer)

Directors:

Janaki Akella
Juanita Powell Baranco
Jon A. Boscia
Henry A. Clark III
Anthony F. Earley, Jr.
David J. Grain
Veronica M. Hagen
Donald M. James
John D. Johns
Dale E. Klein
Ernest J. Moniz
William G. Smith, Jr.
Steven R. Specker
Larry D. Thompson
E. Jenner Wood III

By: /s/Melissa K. Caen
(Melissa K. Caen, Attorney-in-fact)

Date: February 19, 2019

ALABAMA POWER COMPANY

SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized. The signature of the undersigned company shall be deemed to relate only to matters having reference to such company and any subsidiaries thereof.

ALABAMA POWER COMPANY

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

By: /s/Melissa K. Caen
(Melissa K. Caen, Attorney-in-fact)

Date: February 19, 2019

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed below by the following persons on behalf of the registrant and in the capacities and on the dates indicated. The signature of each of the undersigned shall be deemed to relate only to matters having reference to the above-named company and any subsidiaries thereof.

Mark A. Crosswhite
Chairman, President, and Chief Executive Officer
(Principal Executive Officer)

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

Anita Allcorn-Walker
Vice President and Comptroller
(Principal Accounting Officer)

Directors:

Whit Armstrong
Angus R. Cooper, III
O. B. Grayson Hall, Jr.
Anthony A. Joseph
James K. Lowder
Robert D. Powers
Catherine J. Randall
C. Dowd Ritter
R. Mitchell Shackleford, III
Phillip M. Webb

By: /s/Melissa K. Caen
(Melissa K. Caen, Attorney-in-fact)

Date: February 19, 2019

GEORGIA POWER COMPANY

SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized. The signature of the undersigned company shall be deemed to relate only to matters having reference to such company and any subsidiaries thereof.

GEORGIA POWER COMPANY

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

By: /s/Melissa K. Caen
(Melissa K. Caen, Attorney-in-fact)

Date: February 19, 2019

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed below by the following persons on behalf of the registrant and in the capacities and on the dates indicated. The signature of each of the undersigned shall be deemed to relate only to matters having reference to the above-named company and any subsidiaries thereof.

W. Paul Bowers
Chairman, President, and Chief Executive Officer
(Principal Executive Officer)

Xia Liu
Executive Vice President, Chief Financial Officer, and Treasurer
(Principal Financial Officer)

David P. Poroch
Comptroller and Vice President
(Principal Accounting Officer)

Directors:

Mark L. Burns
Shantella E. Cooper
Lawrence L. Gellerstedt III
Douglas J. Hertz
Kessel D. Stelling, Jr.
Jimmy C. Tallent
Charles K. Tarbutton
Beverly Daniel Tatum
Clyde C. Tuggle

By: /s/Melissa K. Caen
(Melissa K. Caen, Attorney-in-fact)

Date: February 19, 2019

MISSISSIPPI POWER COMPANY

SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized. The signature of the undersigned company shall be deemed to relate only to matters having reference to such company and any subsidiaries thereof.

MISSISSIPPI POWER COMPANY

By: Anthony L. Wilson
Chairman, President, and Chief Executive Officer

By: /s/Melissa K. Caen
(Melissa K. Caen, Attorney-in-fact)

Date: February 19, 2019

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed below by the following persons on behalf of the registrant and in the capacities and on the dates indicated. The signature of each of the undersigned shall be deemed to relate only to matters having reference to the above-named company and any subsidiaries thereof.

Anthony L. Wilson
Chairman, President, and Chief Executive Officer
(Principal Executive Officer)

Moses H. Feagin
Vice President, Treasurer, and
Chief Financial Officer
(Principal Financial Officer)

Cynthia F. Shaw
Comptroller
(Principal Accounting Officer)

Directors:

Carl J. Chaney
L. Royce Cumbest
Thomas M. Duff
Mark E. Keenum
Christine L. Pickering
M.L. Waters
Camille S. Young

By: /s/Melissa K. Caen
(Melissa K. Caen, Attorney-in-fact)

Date: February 19, 2019

Supplemental Information to be Furnished with Reports Filed Pursuant to Section 15(d) of the Act by Registrants Which Have Not Registered Securities Pursuant to Section 12 of the Act:

Mississippi Power is not required to send an annual report or proxy statement to its sole shareholder and parent company, The Southern Company, and will not prepare such a report after filing this Annual Report on Form 10-K for fiscal year 2018. Accordingly, Mississippi Power will not file an annual report with the Securities and Exchange Commission.

SOUTHERN POWER COMPANY

SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized. The signature of the undersigned company shall be deemed to relate only to matters having reference to such company and any subsidiaries thereof.

SOUTHERN POWER COMPANY

By: Mark S. Lantrip
Chairman, President and Chief Executive Officer

By: /s/Melissa K. Caen
(Melissa K. Caen, Attorney-in-fact)

Date: February 19, 2019

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed below by the following persons on behalf of the registrant and in the capacities and on the dates indicated. The signature of each of the undersigned shall be deemed to relate only to matters having reference to the above-named company and any subsidiaries thereof.

Mark S. Lantrip
Chairman, President, and Chief Executive Officer
(Principal Executive Officer)

William C. Grantham
Senior Vice President, Chief Financial Officer, and Treasurer
(Principal Financial Officer)

Elliott L. Spencer
Comptroller and Corporate Secretary
(Principal Accounting Officer)

Directors:

Stan W. Connally
Andrew W. Evans
Thomas A. Fanning
Kimberly S. Greene
James Y. Kerr, II
Christopher C. Womack

By: /s/Melissa K. Caen
(Melissa K. Caen, Attorney-in-fact)

Date: February 19, 2019

SOUTHERN COMPANY GAS

SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized. The signature of the undersigned company shall be deemed to relate only to matters having reference to such company and any subsidiaries thereof.

SOUTHERN COMPANY GAS

By: Kimberly S. Greene
Chairman, President, and Chief Executive Officer

By: /s/Melissa K. Caen
(Melissa K. Caen, Attorney-in-fact)

Date: February 19, 2019

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed below by the following persons on behalf of the registrant and in the capacities and on the dates indicated. The signature of each of the undersigned shall be deemed to relate only to matters having reference to the above-named company and any subsidiaries thereof.

Kimberly S. Greene
Chairman, President, and Chief Executive Officer
(Principal Executive Officer)

Daniel S. Tucker
Executive Vice President, Chief Financial Officer, and Treasurer
(Principal Financial Officer)

Grace A. Kolvereid
Senior Vice President and Comptroller
(Principal Accounting Officer)

Directors:

Sandra N. Bane
Thomas D. Bell, Jr.
Charles R. Crisp
Brenda J. Gaines
John E. Rau
James A. Rubright

By: /s/Melissa K. Caen
(Melissa K. Caen, Attorney-in-fact)

Date: February 19, 2019

Supplemental Information to be Furnished with Reports Filed Pursuant to Section 15(d) of the Act by Registrants Which Have Not Registered Securities Pursuant to Section 12 of the Act:

Southern Company Gas is not required to send an annual report or proxy statement to its sole shareholder and parent company, The Southern Company, and will not prepare such a report after filing this Annual Report on Form 10-K for fiscal year 2018. Accordingly, Southern Company Gas will not file an annual report with the Securities and Exchange Commission.