


REAL Solutions

SOUTHERN COMPANY *2015 Annual Report*

"We do much more than keep the lights on. We provide hope for customers–hope for a better way to meet their economic challenges, better communities in which to live and a better future for their children."

THOMAS A. FANNING–*Chairman, President & CEO*
Southern Company

Learn more about REAL Solutions for real life energy challenges at **www.southerncompany.com/ar15**.

This Annual Report contains forward-looking statements. See page 49 for a cautionary statement regarding forward-looking information.

Dear Fellow Shareholders,

This is such an important time in America. With a volatile global economy, challenges in the Middle East and ongoing economic uncertainty here at home, Americans are looking for hope and a way to move forward and "play offense" in this unsettled environment. Southern Company is leading our industry and, in many ways, our nation to provide real solutions to drive our economy, create jobs, grow personal incomes and make American lives better.

This past year was a memorable one in which our franchise operations continued to perform beautifully. We made significant progress with construction at Georgia Power's Plant Vogtle and Mississippi Power's Kemper facility. We continued to expand our renewable energy portfolio. We announced a merger with AGL Resources.

These are all major accomplishments of which I am quite proud. However, none is any more important than the work that is accomplished to deliver practical energy solutions that provide value for customers who must make hard "kitchen table" financial decisions each and every day. We provide hope for those customers–hope for a better way to meet their economic challenges, better communities in which to live and a better future for their children.

It is for these reasons we have selected "Real Solutions" as the theme of this year's annual report, highlighting customer solutions throughout our region.

The following are updates on our five strategic priorities and the proposed merger with AGL Resources:

EXCEL AT THE FUNDAMENTALS

Even as we lead the innovation-centered transformation of our business into the future, we remain steadfastly focused on customers. To put it another way, there is nothing more fundamental to our business than our quest to provide superior customer service.

In 2015, Southern Company earned the Edison Electric Institute's (EEI) National Key Accounts Customer Service Award for the 12th time. EEI also honored Alabama Power with its Emergency Recovery Award for going "above and beyond" to restore service after summer storms left more than 100,000 customers without electricity–the seventh time Alabama Power has received this honor.

Our traditional operating companies continue to be among the most highly rated utilities for customer satisfaction by J.D. Power, which ranks companies on the basis of power quality and reliability, price, billing and payment, corporate citizenship, communications and customer service.

Also, for the 18th consecutive year, Southern Company and its traditional operating companies ranked in the top quartile in the Customer Value Benchmark survey, our annual peer comparison of U.S. electric utilities based on residential, general business and large business customer value scores.

ACHIEVE SUCCESS WITH MAJOR CONSTRUCTION PROJECTS

The combined-cycle at Mississippi Power's Kemper County energy facility has been performing exceptionally well on natural gas for more than a year and a half, providing a third of all electricity used by Mississippi Power customers in 2015.

Construction of the two new nuclear units at Georgia Power's Plant Vogtle, among the first to be built in the United States in more than three decades, is also progressing well. Current in-service dates are estimated to be 2019 for Unit 3 and 2020 for Unit 4. Once units 3 and 4 join the existing two Vogtle units already in operation, Plant Vogtle is expected to generate more electricity than any other U.S. nuclear facility, enough to power more than 1 million homes and businesses.

SUPPORT THE BUILDING OF A NATIONAL ENERGY POLICY

We continue to engage constructively on a variety of fronts to advocate for a common sense national energy policy. This includes legislation, regulatory policy and–when we deem it to be in the best interests of customers–litigation. We remain committed to energy innovation, and we are the only company in America proactively developing the full portfolio of generation resources–natural gas, 21st century coal, nuclear and renewables such as wind and solar–together with an emphasis on energy efficiency.

PROMOTE ENERGY INNOVATION

Here at Southern Company, we like to say that innovation is in our DNA. In 2015, we launched our Energy Innovation Center, a dedicated facility that will incubate new ideas in our ongoing efforts to develop the energy solutions of tomorrow. Our commitment to innovation is not confined to any particular team or facility, however, as we actively encourage a culture of innovation throughout the Southern Company system.

Our Southern Power subsidiary experienced a landmark year for growth with the acquisition of nearly five times more projects and facilities in 2015 than ever before. This includes 14 renewable projects and facilities with a combined generating capacity of more than 1,600 megawatts, 1,200 of which are owned by Southern Power, bringing its total renewable portfolio to more than 1,800 megawatts, including capacity announced, acquired or under construction.

Southern Company has been awarded up to $40 million in grants from the U.S. Department of Energy to explore and develop advanced nuclear reactor technologies. We announced an agreement to acquire PowerSecure International in order to address a growing demand for distributed generation solutions.

Finally, we are engaged with the Pentagon and all branches of the United States military to assist the 19 military bases in our region with some very ambitious energy goals, including the development and implementation of solar projects, electric vehicles and electric vehicle charging infrastructure.

VALUE AND DEVELOP OUR PEOPLE

In 2015, we completed 426 transfers of employees between our subsidiaries, providing new opportunities for employees to expand their knowledge of our industry and business operations. We promoted 225 employees to supervisory roles for the first time.

Southern Company was named one of the 40 Best Companies for Diversity by Black Enterprise magazine, recognizing a commitment to diversity reflected in our leadership, our workforce and our suppliers, including our success in recruiting military veterans and individuals with disabilities. Southern Company was the only energy company recognized in DiversityInc's Top 10 Companies for Veterans and the highest-ranked utility in G.I. Jobs' Top 100 Military Friendly Employer® listing.

AGL RESOURCES

In August, we announced an agreement to acquire AGL Resources. The addition of AGL Resources' network of natural gas assets and businesses will provide a broader, more robust platform for long-term success, which we expect to result in increased opportunities to invest in future infrastructure and energy solutions. With the ongoing evolution of our regulatory environment and the technology revolution taking place in energy production, Southern Company should be well positioned for a future that we expect to require more natural gas infrastructure.

Our record of accomplishment in 2015 is the direct result of our focus on real solutions and the customer-centered business model that serves as the guiding principle for all we do. It's a simple business model, historically acclaimed by customers and Wall Street alike. I believe it will continue to serve us well for years to come.

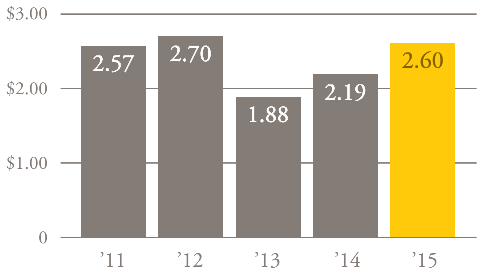
Rest assured that both our management team and the 26,000 employees across the Southern Company system remain diligent in our efforts to provide exceptional value to customers and shareholders. It is a privilege to serve you.

Sincerely,

Thomas A. Fanning

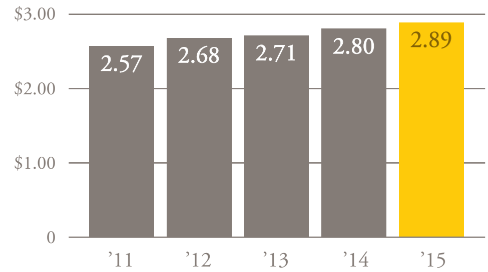
Thomas A. Fanning
March 24, 2016

Financial Highlights



Basic Earnings Per Share

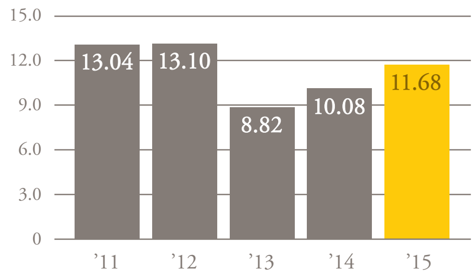
(In Dollars)



Basic Earnings Per Share Excluding Kemper IGCC Impacts, AGL Resources Acquisition Costs, Leveraged Lease Restructure Charge and MC Asset Recovery Insurance Settlements*

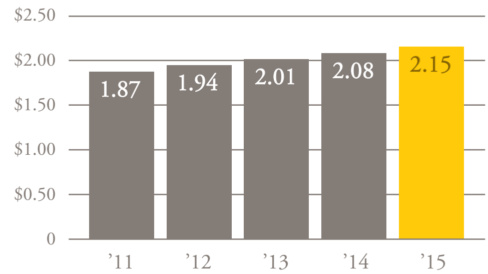
(In Dollars)

* *Not a financial measure under generally accepted accounting principles. See page 11 for additional information and specific adjustments made to this measure by year.*



Return On Average Common Equity

(Percent)

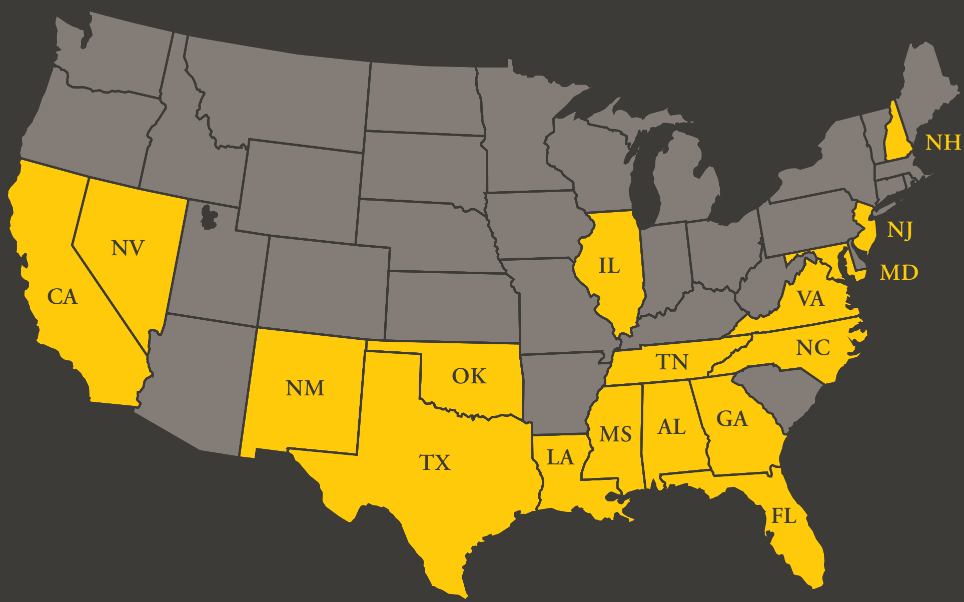


Dividends Per Share

(In Dollars)

	2015	2014	*Change*
Operating Revenues *(In Millions)*	**$17,489**	$18,467	(5.3)%
Earnings *(In Millions)*	**$2,367**	$1,963	20.6 %
Basic Earnings Per Share	**$2.60**	$2.19	18.7 %
Diluted Earnings Per Share	**$2.59**	$2.18	18.8 %
Dividends Per Share *(Amount Paid)*	**$2.1525**	$2.0825	3.4 %
Dividend Yield *(Year-End, Percent)*	**4.6**	4.2	9.5 %
Average Shares Outstanding *(In Millions)*	**910**	897	1.4 %
Return On Average Common Equity *(Percent)*	**11.68**	10.08	15.9 %
Book Value Per Share	**$22.59**	$21.98	2.8 %
Market Price Per Share *(Year-End, Closing)*	**$46.79**	$49.11	(4.7)%
Total Market Value Of Common Stock *(Year-End, In Millions)*	**$42,659**	$44,581	(4.3)%
Total Assets *(In Millions)*	**$78,318**	$70,233	11.5 %
Total Kilowatt-Hour Sales *(In Millions)*	**190,989**	194,425	(1.8)%
Retail	**160,484**	161,639	(0.7)%
Wholesale	**30,505**	32,786	(7.0)%
Total Traditional Operating Company Customers *(Year-End, In Thousands)*	**4,546**	4,504	0.9 %

Combined Service Territory*



Operations In
17 States

11
Electric & Natural Gas Utilities

31,000
Total Employees

9 Million
Utility Customers

More Than
1 Million
Retail Customers

* Combined service territory shown is pro forma for the completion of the proposed merger.

The Pending Acquisition of AGL Resources

In August, Southern Company and AGL Resources announced an agreement to create America's leading electric and natural gas utility company. Pending regulatory approval and completion of the transaction, the combined companies will become the second-largest utility company in the United States as measured by number of customers.

The merger will aggregate 11 regulated electric and natural gas distribution companies, serving some 9 million customers with a projected regulated rate base of approximately $50 billion. The combined company will have a generating capacity of approximately 44,000 megawatts and operate nearly 200,000 miles of electric transmission and distribution lines and more than 80,000 miles of gas pipelines.

Southern Company is already one of the largest consumers of natural gas in the U.S., with natural gas accounting for nearly half of the electricity generated to serve customers' needs. We expect the addition of AGL Resources' network of natural gas assets and businesses to provide a more robust platform for long-term success with increased opportunities to invest in additional infrastructure and energy solutions. A natural outgrowth of our commitment to provide real solutions for America's energy future, the merger is expected to help address one of the key challenges facing today's energy industry–the development of infrastructure necessary to transport affordable natural gas to areas where it is increasingly needed.

Upon finalization of the merger, AGL Resources will become a new wholly owned subsidiary of Southern Company in a transaction with an enterprise value of approximately $12 billion, including a total equity value of approximately $8 billion. Until the transaction has received all necessary approvals and has closed, the companies will continue to operate as separate independent entities. After the transaction closes, AGL Resources will continue to maintain its own management team and board of directors.

We believe this merger will be attractive to investors because we expect it to create a leading platform that is well positioned for growth across the energy value chain. The transaction is anticipated to be accretive to Southern Company's earnings per share in the first full year following its closing.

Likewise, we believe this merger makes sense for customers because we expect it to strengthen reliability and improve current and future energy infrastructure development. The cornerstone strength of both companies is our shared commitment to providing customers with outstanding service and innovative energy solutions. The transaction is not expected to increase electric or gas rates for any of the utilities of either Southern Company or AGL Resources.

The companies expect to complete the transaction in the second half of 2016.

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SOUTHERN COMPANY BUSINESS

The Southern Company (Southern Company or the Company) is a holding company that owns all of the outstanding common stock of Alabama Power, Georgia Power, Gulf Power, and Mississippi Power, each of which is an operating public utility company. The traditional operating companies supply electric service in the states of Alabama, Georgia, Florida, and Mississippi. The traditional operating companies are vertically integrated utilities that own generation, transmission, and distribution facilities.

Southern Company owns all of the common stock of Southern Power Company, which is also an operating public utility company. Southern Power constructs, acquires, owns, and manages generation assets, including renewable energy projects, and sells electricity at market-based rates in the wholesale market.

Southern Company also owns all of the outstanding common stock or membership interests of SouthernLINC Wireless, Southern Nuclear, SCS, Southern Holdings, and other direct and indirect subsidiaries. SouthernLINC Wireless provides digital wireless communications for use by Southern Company and its subsidiary companies and markets these services to the public and also provides wholesale fiber optic solutions to telecommunication providers in the Southeast. Southern Nuclear operates and provides services to Alabama Power's and Georgia Power's nuclear plants and is currently developing Plant Vogtle Units 3 and 4, which are co-owned by Georgia Power. SCS is the Southern Company system service company providing, at cost, specialized services to Southern Company and its subsidiary companies. Southern Holdings is an intermediate holding subsidiary, primarily for Southern Company's investments in leveraged leases and also for energy services.

On August 23, 2015, Southern Company entered into the Merger Agreement to acquire AGL Resources. Under the terms of the Merger Agreement, subject to the satisfaction or waiver (if permissible under applicable law) of specified conditions, Merger Sub will be merged with and into AGL Resources. AGL Resources will survive the Merger and become a wholly-owned, direct subsidiary of Southern Company. Upon the consummation of the Merger, each share of common stock of AGL Resources issued and outstanding immediately prior to the effective time of the Merger, other than shares owned by AGL Resources as treasury stock, shares owned by a subsidiary of AGL Resources, and any shares owned by shareholders who have properly exercised and perfected dissenters' rights, will be converted into the right to receive $66 in cash, without interest and less any applicable withholding taxes. Other equity-based securities of AGL Resources will be cancelled for cash consideration or converted into new awards from Southern Company as described in the Merger Agreement.

SOUTHERN COMPANY COMMON STOCK AND DIVIDEND INFORMATION

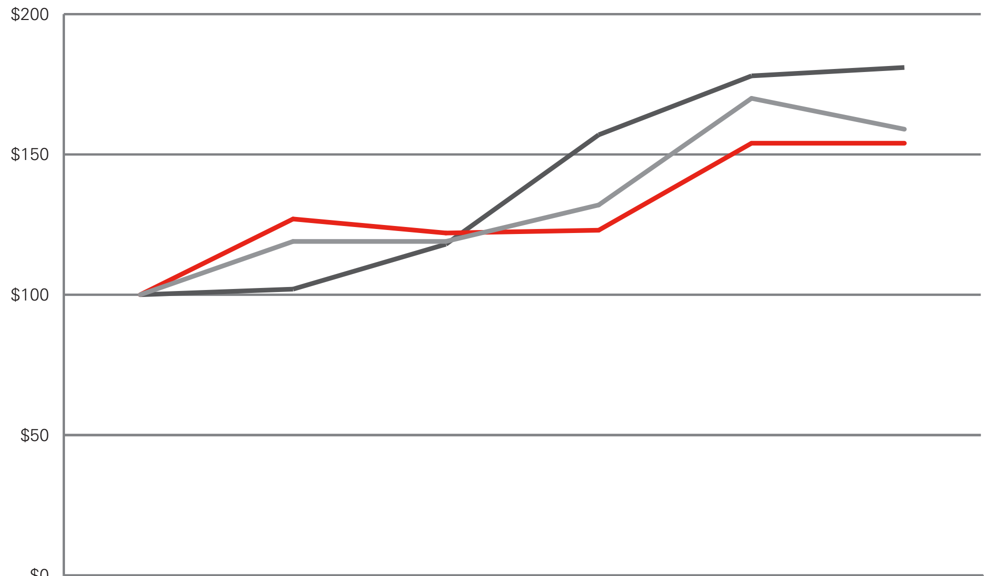
The common stock of Southern Company is listed and traded on the New York Stock Exchange (NYSE). The common stock is also traded on regional exchanges across the U.S. Dividends are payable at the discretion of the board of directors.

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

	High	Low
2015		
First Quarter	$ 53.16	$ 43.55
Second Quarter	45.44	41.40
Third Quarter	46.84	41.81
Fourth Quarter	47.50	43.38
2014		
First Quarter	$ 44.00	$ 40.27
Second Quarter	46.81	42.55
Third Quarter	45.47	41.87
Fourth Quarter	51.28	43.55

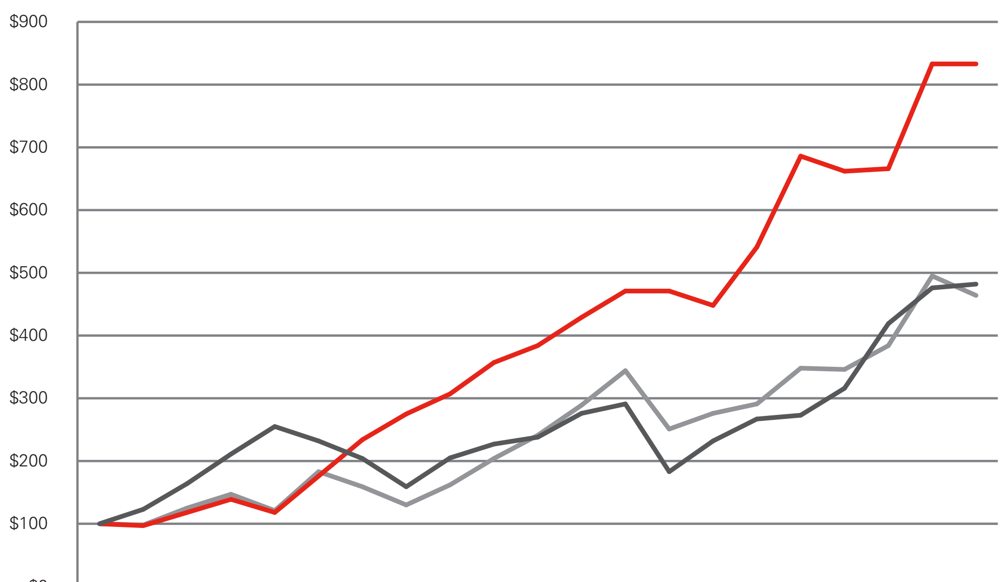
The dividend paid per share of Southern Company's common stock was 52.50¢ for the first quarter 2015 and 54.25¢ each for the second, third, and fourth quarters of 2015. In 2014, Southern Company paid a dividend per share of 50.75¢ for the first quarter and 52.50¢ each for the second, third, and fourth quarters.

FIVE YEAR CUMULATIVE PERFORMANCE GRAPH



	2010	2011	2012	2013	2014	2015
S&P 500 (TR)	100	102	118	157	178	181
Southern Company	100	127	122	123	154	154
Philadelphia Utilities Index	100	119	119	132	170	159

TWENTY YEAR CUMULATIVE PERFORMANCE GRAPH



	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015
S&P 500 (TR)	100	123	164	211	255	232	204	159	205	227	238	276	291	183	232	267	273	316	419	476	482
Southern Company	100	97	118	139	118	176	234	275	307	357	384	429	471	471	448	541	686	662	666	833	833
Philadelphia Utilities Index	100	98	125	147	121	183	159	130	162	204	241	289	344	251	276	291	348	346	384	495	464

MANAGEMENT'S REPORT ON INTERNAL CONTROL OVER FINANCIAL REPORTING

Southern Company and Subsidiary Companies 2015 Annual Report

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

Under management's supervision, an evaluation of the design and effectiveness of Southern Company's internal control over financial reporting was conducted based on the framework in *Internal Control—Integrated Framework (2013)* issued by the Committee of Sponsoring Organizations of the Treadway Commission. Based on this evaluation, management concluded that Southern Company's internal control over financial reporting was effective as of December 31, 2015.

Deloitte & Touche LLP, an independent registered public accounting firm, as auditors of Southern Company's financial statements, has issued an attestation report on the effectiveness of Southern Company's internal control over financial reporting as of December 31, 2015. Deloitte & Touche LLP's report on Southern Company's internal control over financial reporting is included herein.

Thomas A. Fanning

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

Art P. Beattie

Art P. Beattie
Executive Vice President and Chief Financial Officer

February 26, 2016

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors and Stockholders of The Southern Company

We have audited the accompanying consolidated balance sheets and consolidated statements of capitalization of The Southern Company and Subsidiary Companies (the Company) as of December 31, 2015 and 2014, and the related consolidated statements of income, comprehensive income, stockholders' equity, and cash flows for each of the three years in the period ended December 31, 2015. We also have audited the Company's internal control over financial reporting as of December 31, 2015, based on criteria established in *Internal Control - Integrated Framework (2013)* issued by the Committee of Sponsoring Organizations of the Treadway Commission. The Company's management is responsible for these financial statements, for maintaining effective internal control over financial reporting, and for its assessment of the effectiveness of internal control over financial reporting, included in the accompanying Management's Report on Internal Control Over Financial Reporting (page 8). Our responsibility is to express an opinion on these financial statements and an opinion on the Company's internal control over financial reporting based on our audits.

We conducted our audits in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement and whether effective internal control over financial reporting was maintained in all material respects. Our audits of the financial statements included examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, and evaluating the overall financial statement presentation. Our audit of internal control over financial reporting included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, and testing and evaluating the design and operating effectiveness of internal control based on the assessed risk. Our audits also included performing such other procedures as we considered necessary in the circumstances. We believe that our audits provide a reasonable basis for our opinions.

A company's internal control over financial reporting is a process designed by, or under the supervision of, the company's principal executive and principal financial officers, or persons performing similar functions, and effected by the company's board of directors, management, and other personnel to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. A company's internal control over financial reporting includes those policies and procedures that (1) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (2) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the company are being made only in accordance with authorizations of management and directors of the company; and (3) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the company's assets that could have a material effect on the financial statements.

Because of the inherent limitations of internal control over financial reporting, including the possibility of collusion or improper management override of controls, material misstatements due to error or fraud may not be prevented or detected on a timely basis. Also, projections of any evaluation of the effectiveness of the internal control over financial reporting to future periods are subject to the risk that the controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

In our opinion, the consolidated financial statements (pages 51 to 124) referred to above present fairly, in all material respects, the financial position of Southern Company and Subsidiary Companies as of December 31, 2015 and 2014, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2015, in conformity with accounting principles generally accepted in the United States of America. Also, in our opinion, the Company maintained, in all material respects, effective internal control over financial reporting as of December 31, 2015, based on the criteria established in *Internal Control - Integrated Framework (2013)* issued by the Committee of Sponsoring Organizations of the Treadway Commission.

Deloitte & Touche LLP

Atlanta, Georgia
February 26, 2016

DEFINITIONS

Term	Meaning
2012 MPSC CPCN Order	A detailed order issued by the Mississippi PSC in April 2012 confirming the CPCN originally approved by the Mississippi PSC in 2010 authorizing acquisition, construction, and operation of the Kemper IGCC
2013 ARP	Alternative Rate Plan approved by the Georgia PSC for Georgia Power for the years 2014 through 2016
AFUDC	Allowance for funds used during construction
AGL Resources	AGL Resources Inc.
Alabama Power	Alabama Power Company
APA	Asset purchase agreement
ASC	Accounting Standards Codification
Baseload Act	State of Mississippi legislation designed to enhance the Mississippi PSC's authority to facilitate development and construction of baseload generation in the State of Mississippi
Bridge Agreement	Senior unsecured Bridge Credit Agreement, dated as of September 30, 2015, among Southern Company, the lenders identified therein, and Citibank, N.A.
CCR	Coal combustion residuals
Clean Air Act	Clean Air Act Amendments of 1990
CO_2	Carbon dioxide
COD	Commercial operation date
CPCN	Certificate of public convenience and necessity
CWIP	Construction work in progress
DOE	U.S. Department of Energy
EPA	U.S. Environmental Protection Agency
FERC	Federal Energy Regulatory Commission
FFB	Federal Financing Bank
GAAP	U.S. generally accepted accounting principles
Georgia Power	Georgia Power Company
Gulf Power	Gulf Power Company
IGCC	Integrated coal gasification combined cycle
IRS	Internal Revenue Service
ITC	Investment tax credit
Kemper IGCC	IGCC facility under construction by Mississippi Power in Kemper County, Mississippi
KWH	Kilowatt-hour
LIBOR	London Interbank Offered Rate
Merger	The merger of Merger Sub with and into AGL Resources on the terms and subject to the conditions set forth in the Merger Agreement, with AGL Resources continuing as the surviving corporation and a wholly-owned, direct subsidiary of Southern Company
Merger Agreement	Agreement and Plan of Merger, dated as of August 23, 2015, among Southern Company, AGL Resources, and Merger Sub
Merger Sub	AMS Corp., a wholly-owned, direct subsidiary of Southern Company
Mirror CWIP	A regulatory liability account for use in mitigating future rate impacts for Mississippi Power customers
Mississippi Power	Mississippi Power Company

Term	Meaning
mmBtu	Million British thermal units
Moody's	Moody's Investors Service, Inc.
MPUS	Mississippi Public Utilities Staff
MW	Megawatt
NCCR	Georgia Power's Nuclear Construction Cost Recovery
NDR	Alabama Power's Natural Disaster Reserve
NRC	U.S. Nuclear Regulatory Commission
OCI	Other comprehensive income
Plant Vogtle Units 3 and 4	Two new nuclear generating units under construction at Georgia Power's Plant Vogtle
power pool	The operating arrangement whereby the integrated generating resources of the traditional operating companies and Southern Power Company (excluding subsidiaries) are subject to joint commitment and dispatch in order to serve their combined load obligations
PPA	Power purchase agreement
PSC	Public Service Commission
Rate CNP	Alabama Power's Rate Certificated New Plant
Rate CNP Compliance	Alabama Power's Rate Certificated New Plant Compliance
Rate CNP Environmental	Alabama Power's Rate Certificated New Plant Environmental
Rate CNP PPA	Alabama Power's Rate Certificated New Plant Power Purchase Agreement
Rate ECR	Alabama Power's Rate Energy Cost Recovery
Rate NDR	Alabama Power's Rate Natural Disaster Reserve
Rate RSE	Alabama Power's Rate Stabilization and Equalization plan
ROE	Return on equity
S&P	Standard and Poor's Rating Services, a division of The McGraw Hill Companies, Inc.
SCS	Southern Company Services, Inc. (the Southern Company system service company)
SEC	U.S. Securities and Exchange Commission
SEGCO	Southern Electric Generating Company
SMEPA	South Mississippi Electric Power Association
Southern Company system	The Southern Company, the traditional operating companies, Southern Power, SEGCO, Southern Nuclear, SCS, SouthernLINC Wireless, and other subsidiaries
SouthernLINC Wireless	Southern Communications Services, Inc.
Southern Nuclear	Southern Nuclear Operating Company, Inc.
Southern Power	Southern Power Company and its subsidiaries
traditional operating companies	Alabama Power, Georgia Power, Gulf Power, and Mississippi Power

Basic Earnings Per Share Excluding Kemper IGCC Impacts, AGL Resources Acquisition Costs, Leveraged Lease Restructure Charge, and MC Asset Recovery Insurance Settlements

Basic earnings per share in 2015 of $2.60 plus an excluded 25-cent charge related to Mississippi Power's construction of the Kemper IGCC project and plus an excluded 3 cents related to the costs of the proposed merger with AGL Resources, plus an excluded MC Asset Recovery insurance settlement charge of 1 cent. Basic earnings per share in 2014 of $2.19 plus an excluded 59-cent charge related to Mississippi Power's construction of the Kemper IGCC project and plus an excluded 2 cents related to the reversal of previously recognized revenues recorded in 2014 and 2013 and the recognition of carrying costs associated with the 2015 Mississippi Supreme Court decision which reversed the Mississippi Public Service Commission's March 2013 rate order related to the Kemper IGCC project. Basic earnings per share in 2013 of $1.88 plus an excluded 83-cent charge related to Mississippi Power's construction of the Kemper IGCC project, plus an excluded 2-cent charge related to the restructuring of a leveraged lease investment and minus an excluded MC Asset Recovery insurance settlement of 2 cents. Basic earnings per share in 2012 of $2.70 minus an excluded MC Asset Recovery insurance settlement of 2 cents.

MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS

OVERVIEW

Business Activities

The Southern Company (Southern Company or the Company) is a holding company that owns all of the common stock of the traditional operating companies and Southern Power Company and owns other direct and indirect subsidiaries. The primary business of the Southern Company system is electricity sales by the traditional operating companies and Southern Power. The four traditional operating companies are vertically integrated utilities providing electric service in four Southeastern states. Southern Power constructs, acquires, owns, and manages generation assets, including renewable energy projects, and sells electricity at market-based rates in the wholesale market.

Many factors affect the opportunities, challenges, and risks of the Southern Company system's electricity business. These factors include the traditional operating companies' ability to maintain a constructive regulatory environment, to maintain and grow energy sales, and to effectively manage and secure timely recovery of costs. These costs include those related to projected long-term demand growth, increasingly stringent environmental standards, reliability, fuel, capital expenditures, including new plants, and restoration following major storms. Construction continues on Plant Vogtle Units 3 and 4 (45.7% ownership interest by Georgia Power in the two units, each with approximately 1,100 MWs) and Mississippi Power's 582-MW Kemper IGCC. On December 3, 2015, the Mississippi PSC issued an order, based on a stipulation between Mississippi Power and the MPUS, authorizing Mississippi Power to implement rates that provide for the recovery of approximately $126 million annually related to Kemper IGCC assets previously placed in service. Further proceedings related to cost recovery for the Kemper IGCC are expected after the remainder of the Kemper IGCC is placed in service which is currently expected in the third quarter 2016. See Note 3 to the financial statements under "Integrated Coal Gasification Combined Cycle" for additional information. In addition, on December 31, 2015, Georgia Power and the other parties to the commercial litigation related to the construction of Plant Vogtle Units 3 and 4 entered into a settlement agreement resulting in the dismissal of the litigation. See Note 3 to the financial statements under "Retail Regulatory Matters – Georgia Power – Nuclear Construction" for more information.

Each of the traditional operating companies has various regulatory mechanisms that operate to address cost recovery. Effectively operating pursuant to these regulatory mechanisms and appropriately balancing required costs and capital expenditures with customer prices will continue to challenge the Southern Company system for the foreseeable future. See Note 3 to the financial statements under "Retail Regulatory Matters" and "Integrated Coal Gasification Combined Cycle" for additional information.

Another major factor is the profitability of the competitive market-based wholesale generating business. Southern Power's strategy is to acquire, construct, and sell power plants, including renewable energy projects, and to enter into PPAs primarily with investor-owned utilities, independent power producers, municipalities, and electric cooperatives.

Southern Company's other business activities include investments in leveraged lease projects and telecommunications. Management continues to evaluate the contribution of each of these activities to total shareholder return and may pursue acquisitions and dispositions accordingly.

Proposed Merger with AGL Resources

On August 23, 2015, Southern Company entered into the Merger Agreement to acquire AGL Resources. Under the terms of the Merger Agreement, subject to the satisfaction or waiver (if permissible under applicable law) of specified conditions, Merger Sub will be merged with and into AGL Resources. AGL Resources will survive the Merger and become a wholly-owned, direct subsidiary of Southern Company. Upon the consummation of the Merger, each share of common stock of AGL Resources issued and outstanding immediately prior to the effective time of the Merger (Effective Time), other than shares owned by AGL Resources as treasury stock, shares owned by a subsidiary of AGL Resources, and any shares owned by shareholders who have properly exercised and perfected dissenters' rights, will be converted into the right to receive $66 in cash, without interest and less any applicable withholding taxes (Merger Consideration). Other equity-based securities of AGL Resources will be cancelled for cash consideration or converted into new awards from Southern Company as described in the Merger Agreement.

Southern Company intends to initially fund the cash consideration for the Merger using a mix of debt and equity. Southern Company finances its capital needs on a portfolio basis and expects to issue approximately $8.0 billion in debt prior to closing the Merger and approximately $1.2 billion in equity during 2016. This capital is expected to provide funding for the Merger, Southern Power growth opportunities, and other Southern Company system capital projects. In addition, Southern Company entered into the $8.1 billion Bridge Agreement on September 30, 2015 to provide financing for the Merger in the event long-term financing is not available.

The Merger was approved by AGL Resources' shareholders on November 19, 2015, and the waiting period under the Hart-Scott-Rodino Antitrust Improvements Act of 1976 expired on December 4, 2015. Consummation of the Merger remains subject to the satisfaction or waiver of certain closing conditions, including, among others, (i) the approval of the California Public Utilities Commission, Georgia PSC, Illinois Commerce Commission, Maryland PSC, and New Jersey Board of Public Utilities, and other approvals required under applicable state laws, and the approval of the Federal Communications Commission (FCC) for the transfer of control over the FCC licenses of certain subsidiaries of AGL Resources, (ii) the absence of a judgment, order, decision, injunction, ruling, or other finding or agency requirement of a governmental entity prohibiting the consummation of the Merger, and (iii) other customary closing conditions, including (a) subject to certain materiality qualifiers, the accuracy of each party's representations and warranties and (b) each party's performance in all material respects of its obligations under the Merger Agreement. Southern Company completed the required state regulatory applications in the fourth quarter 2015 and the required FCC filings in February 2016. On February 24, 2016, a stipulation and settlement agreement between Southern Company, AGL Resources, the Maryland PSC Staff, and the Maryland Office of People's Counsel was filed with the Maryland PSC. The proposed settlement remains subject to the approval of the Maryland PSC. Additionally, Southern Company received the approval of the Virginia State Corporation Commission in February 2016.

Subject to certain limitations, either party may terminate the Merger Agreement if the Merger is not consummated by August 23, 2016, which date may be extended by either party to February 23, 2017 if, on August 23, 2016, all conditions to closing other than those relating to (i) regulatory approvals and (ii) the absence of legal restraints preventing consummation of the Merger (to the extent relating to regulatory approvals) have been satisfied. Upon termination of the Merger Agreement under certain specified circumstances, AGL Resources will be required to pay Southern Company a termination fee of $201 million or reimburse Southern Company's expenses up to $5 million (which reimbursement shall reduce on a dollar-for-dollar basis any termination fee subsequently payable by AGL Resources). Southern Company currently expects to complete the transaction in the second half of 2016.

Prior to the Merger, Southern Company and AGL Resources will continue to operate as separate companies. Accordingly, except for specific references to the pending Merger, the descriptions of strategy and outlook and the risks and challenges Southern Company faces, and the discussion and analysis of results of operations and financial condition set forth herein relate solely to Southern Company. See Note 12 to the financial statements under "Southern Company – Proposed Merger with AGL Resources" for additional information regarding the Merger.

During 2015, the Company incurred external transaction costs for financing, legal, and consulting services associated with the proposed Merger of approximately $41 million.

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

Key Performance Indicators

In striving to achieve superior risk-adjusted returns while providing cost-effective energy to more than four million customers, the Southern Company system continues to focus on several key performance indicators. These indicators include customer satisfaction, plant availability, 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.

Peak season equivalent forced outage rate (Peak Season EFOR) is an indicator of fossil/hydro plant availability and efficient generation fleet operations during the months when generation needs are greatest. The rate is calculated by dividing the number of hours of forced outages by total generation hours. The Southern Company system's fossil/hydro 2015 Peak Season EFOR was better than the target. Transmission and distribution system reliability performance is measured by the frequency and duration of outages. Performance targets for reliability are set internally based on historical performance. The Southern Company system's performance for 2015 was below the target for these transmission and distribution reliability measures primarily due to the level of storm activity in the service territory during the year. Primarily as a result of charges for estimated probable losses related to construction of the Kemper

IGCC, Southern Company's EPS for 2015 did not meet the target on a GAAP basis. See RESULTS OF OPERATIONS – "Estimated Loss on Kemper IGCC" herein and Note 3 to the financial statements under "Integrated Coal Gasification Combined Cycle" for additional information.

Excluding the charges for estimated probable losses related to construction of the Kemper IGCC, AGL Resources acquisition costs, and additional costs related to an insurance settlement, Southern Company's 2015 results compared with its targets for some of these key indicators are reflected in the following chart:

Key Performance Indicator	2015 Target Performance	2015 Actual Performance
System Customer Satisfaction	Top quartile in customer surveys 6.02% or less	Top quartile
Peak Season System EFOR — fossil/hydro	$2.76-$2.88	1.40%
Basic EPS — As Reported		$2.60
Estimated Loss on Kemper IGCC[(a)]		$0.25
AGL Resources Acquisition Costs[(b)]		$0.03
Additional MC Asset Recovery Settlement Costs[(c)]		$0.01
EPS, excluding items*		$2.89

* The following three items are excluded from the EPS calculation:

(a) The estimated probable losses of $226 million after-tax, or $0.25 per share, related to Mississippi Power's construction of the Kemper IGCC. The estimated probable losses related to the construction of the Kemper IGCC significantly impacted the presentation of EPS in the table above, and any similar charges are items that may occur with uncertain frequency in the future. See RESULTS OF OPERATIONS – "Estimated Loss on Kemper IGCC" herein and Note 3 to the financial statements under "Integrated Coal Gasification Combined Cycle" for additional information.

(b) The $31 million after-tax, or $0.03 per share, related to costs of the proposed Merger. Further costs related to the proposed Merger are expected to continue to occur in connection with closing the proposed Merger and supporting the related integration. See "Proposed Merger with AGL Resources" herein and Note 12 to the financial statements under "Southern Company – Proposed Merger with AGL Resources" for additional information.

(c) Additional insurance settlement costs of $4 million after-tax, or $0.01 per share, related to the March 2009 litigation settlement with MC Asset Recovery, LLC. Further costs related to the litigation settlement are not expected.

EPS, excluding items does not reflect EPS as calculated in accordance with GAAP. Southern Company management uses the non-GAAP measure of EPS, excluding these items, to evaluate the performance of Southern Company's ongoing business activities and its 2015 performance on a basis consistent with the assumptions used in developing the 2015 performance targets and to compare certain results to prior periods. Southern Company believes this presentation is useful to investors by providing additional information for purposes of evaluating the performance of Southern Company's business activities. This presentation is not meant to be considered a substitute for financial measures prepared in accordance with GAAP.

See RESULTS OF OPERATIONS herein for additional information on the Company's financial performance.

Earnings

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

Consolidated net income attributable to Southern Company was $2.0 billion in 2014, an increase of $319 million, or 19.4%, from the prior year. The increase was primarily related to an increase in retail base rates, as well as colder weather in the first quarter 2014 and warmer weather in the second and third quarters 2014 as compared to the corresponding periods in 2013. The increase in net income was also the result of lower pre-tax charges of $868 million ($536 million after tax) recorded in 2014 compared to pre-tax charges of $1.2 billion ($729 million after tax) recorded in 2013 for revisions of the estimated costs expected to be incurred on Mississippi Power's construction of the Kemper IGCC. These increases were partially offset by increases in non-fuel operations and maintenance expenses.

Basic EPS was $2.60 in 2015, $2.19 in 2014, and $1.88 in 2013. Diluted EPS, which factors in additional shares related to stock-based compensation, was $2.59 in 2015, $2.18 in 2014, and $1.87 in 2013. EPS for 2015 was negatively impacted by $0.04 per share as a result of an increase in the average shares outstanding. See FINANCIAL CONDITION AND LIQUIDITY – "Financing Activities" herein for additional information.

Dividends

Southern Company has paid dividends on its common stock since 1948. Dividends paid per share of common stock were $2.1525 in 2015, $2.0825 in 2014, and $2.0125 in 2013. In January 2016, Southern Company declared a quarterly dividend of 54.25 cents per share. This is the 273rd consecutive quarter that Southern Company has paid a dividend equal to or higher than the previous quarter. For 2015, the actual dividend payout ratio was 83%, while the payout ratio of net income excluding estimated probable losses relating to Mississippi Power's construction of the Kemper IGCC, AGL Resources acquisition costs, and additional costs related to an insurance settlement was 75%.

RESULTS OF OPERATIONS

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

	Amount		
	2015	2014	2013
		(in millions)	
Electricity business	**$ 2,401**	$ 1,969	$ 1,652
Other business activities	**(34)**	(6)	(8)
Net Income	**$ 2,367**	$ 1,963	$ 1,644

Electricity Business

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

A condensed statement of income for the electricity business follows:

	Amount	Increase (Decrease) from Prior Year	
	2015	**2015**	2014
		(in millions)	
Electric operating revenues	**$ 17,442**	**$ (964)**	$ 1,371
Fuel	**4,750**	**(1,255)**	495
Purchased power	**645**	**(27)**	211
Other operations and maintenance	**4,292**	**33**	481
Depreciation and amortization	**2,020**	**91**	43
Taxes other than income taxes	**995**	**16**	47
Estimated loss on Kemper IGCC	**365**	**(503)**	(312)
Total electric operating expenses	**13,067**	**(1,645)**	965
Operating income	**4,375**	**681**	406
Allowance for equity funds used during construction	**226**	**(19)**	55
Interest income	**22**	**4**	—
Interest expense, net of amounts capitalized	**774**	**(20)**	6
Other income (expense), net	**(54)**	**19**	(18)
Income taxes	**1,326**	**273**	118
Net income	**2,469**	**432**	319
Less:			
Dividends on preferred and preference stock of subsidiaries	**54**	**(14)**	2
Net income attributable to noncontrolling interests	**14**	**14**	—
Net Income Attributable to Southern Company	**$ 2,401**	**$ 432**	$ 317

Electric Operating Revenues

Electric operating revenues for 2015 were $17.4 billion, reflecting a $964 million decrease from 2014. Details of electric operating revenues were as follows:

	Amount	
	2015	2014
	(in millions)	
Retail — prior year	**$ 15,550**	$ 14,541
Estimated change resulting from —		
Rates and pricing	**375**	300
Sales growth	**50**	35
Weather	**(59)**	236
Fuel and other cost recovery	**(929)**	438
Retail — current year	**14,987**	15,550
Wholesale revenues	**1,798**	2,184
Other electric operating revenues	**657**	672
Electric operating revenues	**$ 17,442**	$ 18,406
Percent change	**(5.2)%**	8.0%

Retail revenues decreased $563 million, or 3.6%, in 2015 as compared to the prior year. The significant factors driving this change are shown in the preceding table. The increase in rates and pricing in 2015 was primarily due to increased revenues at Alabama Power, associated with an increase in rates under Rate RSE, and at Georgia Power, related to base tariff increases approved by the Georgia PSC in accordance with the 2013 ARP, and increases in collections for financing costs related to the construction of Plant Vogtle Units 3 and 4 through the NCCR tariff, all effective January 1, 2015, as well as higher contributions from variable demand-driven pricing from commercial and industrial customers. The increase in rates and pricing was also due to the implementation of rates for the Kemper IGCC that began in August 2015 at Mississippi Power. The increase was partially offset by the correction of an error affecting billings since 2013 to a small number of large commercial and industrial customers under a rate plan allowing for variable demand-driven pricing at Georgia Power.

Retail revenues increased $1.0 billion, or 6.9%, in 2014 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 2014 was primarily due to increased revenues at Georgia Power related to base tariff increases effective January 1, 2014, as approved by the Georgia PSC in accordance with the 2013 ARP, and increases in collections for financing costs related to the construction of Plant Vogtle Units 3 and 4 through the NCCR tariff, as well as higher contributions from variable demand-driven pricing from commercial and industrial customers. Also contributing to the increase were increased revenues at Alabama Power associated with Rate CNP Environmental primarily resulting from the inclusion of pre-2005 environmental assets and increased revenues at Gulf Power primarily resulting from a retail base rate increase and an increase in the environmental cost recovery clause rate, both effective January 2014, as approved by the Florida PSC.

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

Electric rates for the traditional 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 purchased power costs, and do not affect net income. The traditional operating companies may also have one or more regulatory mechanisms to recover other costs such as environmental and other compliance costs, storm damage, new plants, and PPAs.

Wholesale revenues consist of PPAs primarily with investor-owned utilities and electric cooperatives and short-term opportunity sales. Wholesale revenues from PPAs (other than solar and wind PPAs) have both capacity and energy components. Capacity revenues reflect the recovery of fixed costs and 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 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. Wholesale revenues at Mississippi Power include FERC-regulated municipal and rural association sales as well as market-based sales. Short-term opportunity sales are made at market-based rates that generally provide a margin above the Southern Company system's variable cost to produce the energy.

Wholesale revenues from power sales were as follows:

		2015		2014		2013
				(in millions)		
Capacity and other	**$**	**875**	$	974	$	971
Energy		**923**		1,210		884
Total	**$**	**1,798**	$	2,184	$	1,855

In 2015, wholesale revenues decreased $386 million, or 17.7%, as compared to the prior year due to a $287 million decrease in energy revenues and a $99 million decrease in capacity revenues. The decreases in energy revenues were primarily related to lower fuel costs and lower customer demand due to milder weather as compared to the prior year, partially offset by increases in energy revenues from new solar and wind PPAs at Southern Power. The decreases in capacity revenues were primarily due to the expiration of wholesale contracts in December 2014 at Georgia Power, unit retirements at Georgia Power, and PPA expirations at Southern Power. See FUTURE EARNINGS POTENTIAL – "Other Matters" for information regarding the expiration of long-term sales agreements at Gulf Power for Plant Scherer Unit 3, which will impact future wholesale earnings.

In 2014, wholesale revenues increased $329 million, or 17.7%, as compared to the prior year due to a $326 million increase in energy revenues and a $3 million increase in capacity revenues. The increase in energy revenues was primarily related to increased revenue under existing contracts as well as new solar PPAs and requirements contracts primarily at Southern Power, increased demand resulting from colder weather in the first quarter 2014 as compared to the corresponding period in 2013, and an increase in the average cost of natural gas. The increase in capacity revenues was primarily due to wholesale base rate increases at Mississippi Power, partially offset by a decrease in capacity revenues primarily due to lower customer demand and the expiration of certain requirements contracts at Southern Power.

Other Electric Revenues

Other electric revenues decreased $15 million, or 2.2%, and increased $33 million, or 5.2%, in 2015 and 2014, respectively, as compared to the prior years. The 2015 decrease was primarily due to a $16 million decrease in transmission revenues at Georgia Power primarily as a result of a contract that expired in December 2014 and a $13 million decrease in co-generation steam revenues at Alabama Power, partially offset by an $11 million increase in outdoor lighting revenues at Georgia Power. The 2014 increase was primarily due to increases in open access transmission tariff revenues and transmission service revenues primarily at Alabama Power and Georgia Power, an increase in co-generation steam revenues at Alabama Power, increases in outdoor lighting and solar application fee revenues at Georgia Power, as well as an increase in franchise fees at Gulf Power due to increased retail revenues.

Energy Sales

Changes in revenues are influenced heavily by the change in the volume of energy sold from year to year. KWH sales for 2015 and the percent change from the prior year were as follows:

	Total KWHs	Total KWH Percent Change		Weather-Adjusted Percent Change	
	2015	**2015**	2014	**2015***	2014
	(in billions)				
Residential	**52.1**	**(2.3)%**	5.5%	**0.4%**	—%
Commercial	**53.5**	**0.5**	1.3	**0.9**	(0.4)
Industrial	**54.0**	**(0.4)**	3.3	**(0.3)**	3.3
Other	**0.9**	**(1.4)**	0.9	**(1.3)**	0.7
Total retail	**160.5**	**(0.7)**	3.3	**0.3%**	0.9%
Wholesale	**30.5**	**(7.0)**	21.7		
Total energy sales	**191.0**	**(1.8)%**	6.0%		

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

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

Retail energy sales increased 5.2 billion KWHs in 2014 as compared to the prior year. This increase was primarily the result of colder weather in the first quarter 2014 and warmer weather in the second and third quarters 2014 as compared to the corresponding periods in 2013 and customer growth, partially offset by a decrease in customer usage. The increase in industrial KWH energy sales was primarily due to increased sales in the primary metals, chemicals, paper, non-manufacturing, transportation, and stone, clay, and glass sectors. Weather-adjusted commercial KWH energy sales decreased primarily due to decreased customer usage, partially offset by customer growth. Weather-adjusted residential KWH energy sales were flat compared to the prior year as a result of customer growth offset by decreased customer usage. Household income, one of the primary drivers of residential customer usage, was flat in 2014.

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

Fuel and Purchased Power Expenses

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

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

	2015	2014	2013
Total generation *(billions of KWHs)*	**187**	191	179
Total purchased power *(billions of KWHs)*	**13**	12	12
Sources of generation *(percent)* —			
Coal	**34**	42	39
Nuclear	**16**	16	17
Gas	**46**	39	40
Hydro	**3**	3	4
Other Renewables	**1**	—	—
Cost of fuel, generated *(cents per net KWH)* —			
Coal	**3.55**	3.81	4.01
Nuclear	**0.79**	0.87	0.87
Gas	**2.60**	3.63	3.29
Average cost of fuel, generated *(cents per net KWH)*	**2.64**	3.25	3.17
Average cost of purchased power *(cents per net KWH)**	**6.11**	7.13	5.27

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

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

In 2014, total fuel and purchased power expenses were $6.7 billion, an increase of $706 million, or 11.8%, as compared to the prior year. The increase was primarily the result of a $422 million increase in the volume of KWHs generated primarily due to increased demand resulting from colder weather in the first quarter 2014 and warmer weather in the second and third quarters 2014 as compared to the corresponding periods in 2013 and a $286 million increase in the average cost of fuel and purchased power primarily due to higher natural gas prices.

Fuel and purchased power energy transactions at the traditional operating companies are generally offset by fuel revenues and do not have a significant impact on net income. See FUTURE EARNINGS POTENTIAL – "Retail Regulatory Matters – Retail 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 2015, fuel expense was $4.8 billion, a decrease of $1.3 billion, or 20.9%, as compared to the prior year. The decrease was primarily due to a 28.4% decrease in the average cost of natural gas per KWH generated, a 19.2% decrease in the volume of KWHs generated by coal, and a 6.8% decrease in the average cost of coal per KWH generated, partially offset by a 15.9% increase in the volume of KWHs generated by natural gas.

In 2014, fuel expense was $6.0 billion, an increase of $495 million, or 9.0%, as compared to the prior year. The increase was primarily due to a 12.7% increase in the volume of KWHs generated by coal, a 10.3% increase in the average cost of natural gas per KWH generated, and a 30.7% decrease in the volume of KWHs generated by hydro facilities resulting from less rainfall, partially offset by a 5.0% decrease in the average cost of coal per KWH generated.

Purchased Power

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

In 2014, purchased power expense was $672 million, an increase of $211 million, or 45.8%, as compared to the prior year. The increase was primarily due to a 35.3% increase in the average cost per KWH purchased.

Energy purchases will vary depending on demand for energy within the Southern Company system's 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 $33 million, or 0.8%, in 2015 as compared to the prior year. The increase was primarily related to an $84 million increase in employee compensation and benefits including pension costs, a $62 million increase in generation expenses primarily related to environmental costs, and an $11 million increase in customer accounts, service, and sales costs primarily related to customer incentive and demand-side management programs, partially offset by a $99 million decrease in transmission and distribution costs primarily related to reduced overhead line maintenance and gains from sales of transmission assets and a $32 million decrease in scheduled outage and maintenance costs at generation facilities.

Other operations and maintenance expenses increased $481 million, or 12.7%, in 2014 as compared to the prior year. The increase was primarily related to increases of $149 million in scheduled outage costs at generation facilities, $103 million in other generation expenses primarily related to commodity and labor costs, $103 million in transmission and distribution costs primarily related to overhead line maintenance, $42 million in net employee compensation and benefits including pension costs, and $31 million in customer accounts, service, and sales costs primarily related to customer incentive and demand-side management programs.

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

Depreciation and amortization increased $43 million, or 2.3%, in 2014 as compared to the prior year primarily due to increases in depreciation rates related to environmental assets and the amortization of certain regulatory assets at Alabama Power and the completion of the amortization of certain regulatory liabilities at Georgia Power. Also contributing to the increase were increases at Southern Power in plant in service related to the addition of solar facilities in 2013 and 2014, an increase related to equipment retirements resulting from accelerated outage work, and additional component depreciation as a result of increased production. These increases were largely offset by the amortization of $120 million of the regulatory liability for other cost of removal obligations at Alabama Power.

See Note 1 to the financial statements under "Regulatory Assets and Liabilities" and "Depreciation and Amortization" and Note 3 to the financial statements under "Retail Regulatory Matters – Alabama Power – Rate CNP" and "– Cost of Removal Accounting Order" for additional information.

Taxes Other Than Income Taxes

Taxes other than income taxes increased $16 million, or 1.6%, in 2015 as compared to the prior year primarily due to an increase in ad valorem and property taxes.

Taxes other than income taxes increased $47 million, or 5.0%, in 2014 as compared to the prior year primarily due to increases of $34 million in municipal franchise fees related to higher retail revenues in 2014 and $16 million in payroll taxes primarily related to higher employee benefits.

Estimated Loss on Kemper IGCC

In 2015 and 2014, estimated probable losses on the Kemper IGCC of $365 million and $868 million, respectively, were recorded at Southern Company. These losses reflect revisions of estimated costs expected to be incurred on Mississippi Power's construction of the Kemper IGCC in excess of the $2.88 billion cost cap established by the Mississippi PSC, net of $245 million of grants awarded to the project by the DOE under the Clean Coal Power Initiative Round 2 (DOE Grants) and excluding the cost of the lignite mine and equipment, the cost of the CO_2 pipeline facilities, AFUDC, and certain general exceptions, including change of law, force majeure, and beneficial capital (which exists when Mississippi Power demonstrates that the purpose and effect of the construction cost increase is to produce efficiencies that will result in a neutral or favorable effect on customers relative to the original proposal for the CPCN) (Cost Cap Exceptions). See Note 3 to the financial statements under "Integrated Coal Gasification Combined Cycle" for additional information.

Allowance for Equity Funds Used During Construction

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

AFUDC equity increased $55 million, or 28.9%, in 2014 as compared to the prior year primarily due to additional capital expenditures at the traditional operating companies, primarily related to environmental and transmission projects, as well as Mississippi Power placing the combined cycle and the associated common facilities portion of the Kemper IGCC in service in August 2014.

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

Interest Expense, Net of Amounts Capitalized

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

Interest expense, net of amounts capitalized increased $6 million, or 0.8%, in 2014 as compared to the prior year primarily due to a higher amount of outstanding long-term debt and an increase in interest expense resulting from the deposits received by Mississippi Power in January and October 2014 from SMEPA, partially offset by a decrease in interest expense related to the refinancing of long-term debt at lower rates and an increase in capitalized interest.

See Note 6 to the financial statements for additional information.

Other Income (Expense), Net

Other income (expense), net increased $19 million, or 26.0%, in 2015 as compared to the prior year primarily due to an increase of $9 million in wholesale operating fee revenues, an increase of $9 million in customer contributions in aid of construction at Georgia Power, and an increase due to Mississippi Power's $7 million settlement with the Sierra Club in 2014, partially offset by a decrease in sales of non-utility property at Alabama Power.

Other income (expense), net decreased $18 million, or 32.7%, in 2014 as compared to the prior year primarily due to an $8 million decrease in wholesale operating fee revenues at Georgia Power and $7 million associated with Mississippi Power's settlement with the Sierra Club.

Income Taxes

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

Income taxes increased $118 million, or 12.6%, in 2014 as compared to the prior year primarily due to higher pre-tax earnings, partially offset by an increase in non-taxable AFUDC equity and an increase in federal income tax benefits related to ITCs on Southern Power solar projects placed in service in 2014.

Other Business Activities

Southern Company's other business activities include the parent company (which does not allocate operating expenses to business units), investments in leveraged lease projects, and telecommunications. These businesses are classified in general categories and may comprise one or both of the following subsidiaries: Southern Company Holdings, Inc. (Southern Holdings) invests in various projects, including leveraged lease projects, and SouthernLINC Wireless provides digital wireless communications for use by Southern Company and its subsidiary companies and also markets these services to the public and provides fiber cable services within the Southeast.

On February 24, 2016, Southern Company entered into an Agreement and Plan of Merger to acquire PowerSecure International, Inc. Under the terms of this merger agreement, the stockholders of PowerSecure International, Inc. will be entitled to receive $18.75 in cash for each share of common stock in a transaction with a total purchase price of approximately $431 million. Following this transaction, PowerSecure International, Inc. will become a wholly-owned subsidiary of Southern Company. This transaction is expected to close by the end of the second quarter 2016, subject to, among other items, approval by PowerSecure International, Inc. stockholders and notification, clearance, and reporting requirements under the Hart-Scott-Rodino Antitrust Improvements Act of 1976.

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

	Amount	Increase (Decrease) from Prior Year	
	2015	**2015**	2014
		(in millions)	
Operating revenues	**$ 47**	**$ (14)**	$ 9
Other operations and maintenance	**124**	**29**	27
Depreciation and amortization	**14**	**(2)**	1
Taxes other than income taxes	**2**	**—**	—
Total operating expenses	**140**	**27**	28
Operating income (loss)	**(93)**	**(41)**	(19)
Interest income	**1**	**—**	—
Other income (expense), net	**(8)**	**(18)**	36
Interest expense	**66**	**25**	5
Income taxes	**(132)**	**(56)**	10
Net income (loss)	**$ (34)**	**$ (28)**	$ 2

Operating Revenues

Southern Company's non-electric operating revenues for these other business activities decreased $14 million, or 23.0%, in 2015 as compared to the prior year. The decrease was primarily related to lower operating revenues at Southern Holdings due to higher billings in 2014 related to work performed on a generating plant outage and decreases in revenues at SouthernLINC Wireless related to lower average per subscriber revenue and fewer subscribers due to continued competition in the industry. Non-electric operating revenues for these other businesses increased $9 million, or 17.3%, in 2014 as compared to the prior year. The increase was primarily related to higher operating revenues at Southern Holdings due to higher billings related to work performed on a generating plant outage, partially offset by decreases in revenues at SouthernLINC Wireless related to lower average per subscriber revenue and fewer subscribers due to continued competition in the industry.

Other Operations and Maintenance Expenses

Other operations and maintenance expenses for these other business activities increased $29 million, or 30.5%, in 2015 as compared to the prior year. The increase was primarily due to parent company expenses of $27 million related to the proposed Merger, partially offset by lower operating expenses at Southern Holdings due to work performed on a generating plant outage in 2014. Other operations and maintenance expenses for these other business activities increased $27 million, or 39.7%, in 2014 as compared to the prior year. The increase was primarily related to insurance proceeds received in 2013 related to a litigation settlement with MC Asset Recovery, LLC and higher operating expenses at Southern Holdings due to work performed on a generating plant outage.

Other Income (Expense), Net

Other income (expense), net for these other business activities decreased $18 million in 2015 as compared to the prior year. The decrease was primarily due to parent company expenses of $14 million related to the proposed Merger. Other income (expense), net for these other business activities increased $36 million in 2014 as compared to the prior year. The increase was primarily due to the restructuring of a leveraged lease investment in the first quarter of 2013 and a decrease in charitable contributions in 2014.

Southern Company has several leveraged lease agreements 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. See Note 1 to the financial statements under "Leveraged Leases" for additional information.

Interest Expense

Interest expense for these other business activities increased $25 million, or 61.0%, in 2015 as compared to the prior year primarily due to an increase in outstanding long-term debt. Interest expense for these other business activities increased $5 million, or 13.9%, in 2014 as compared to 2013 primarily due to an increase in outstanding long-term debt, partially offset by the refinancing of long-term debt at lower rates.

Income Taxes

Income taxes for these other business activities decreased $56 million, or 73.7%, in 2015 as compared to the prior year primarily as a result of state income tax benefits realized in 2015 and changes in pre-tax earnings (losses). Income taxes for these other business activities increased $10 million, or 11.6%, in 2014 as compared to the prior year primarily as a result of changes in pre-tax earnings (losses).

Effects of Inflation

The traditional operating companies are subject to rate regulation that is generally based on the recovery of historical and projected costs. The effects of inflation can create an economic loss since the recovery of costs could be in dollars that have less purchasing power. Southern Power is party to long-term contracts reflecting market-based rates, including inflation expectations. Any adverse effect of inflation on Southern Company's results of operations has not been substantial in recent years.

FUTURE EARNINGS POTENTIAL

General

The four traditional operating companies operate as vertically integrated utilities providing electricity to customers within their service areas in the Southeast. Prices for electricity provided to retail customers are set by state PSCs under cost-based regulatory principles. Prices for wholesale electricity sales, interconnecting transmission lines, and the exchange of electric power are regulated by the FERC. Retail rates and earnings are reviewed and may be adjusted periodically within certain limitations. Southern Power continues to focus on long-term capacity contracts. See ACCOUNTING POLICIES – "Application of Critical Accounting Policies and Estimates – Electric Utility Regulation" herein and Note 3 to the financial statements for additional information about regulatory matters.

The results of operations for the past three years are not necessarily indicative of future earnings potential. The level of Southern Company's future earnings depends on numerous factors that affect the opportunities, challenges, and risks of the Southern Company system's primary business of selling electricity. These factors include the traditional operating companies' ability to maintain a constructive regulatory environment that allows for the timely recovery of prudently-incurred costs during a time of increasing costs and the completion and subsequent operation of the Kemper IGCC and Plant Vogtle Units 3 and 4 as well as other ongoing construction projects. Other major factors include the profitability of the competitive wholesale business and successfully expanding investments in renewable and other energy projects. Future earnings for the electricity business in the near term will depend, in part, upon maintaining and growing sales which are subject to a number of factors. These factors include weather, competition, new energy contracts with other utilities and other wholesale customers, energy conservation practiced by customers, the use of alternative energy sources by customers, the price of electricity, the price elasticity of demand, and the rate of economic growth or decline in the service territory. In addition, the level of future earnings for the wholesale business also depends on numerous factors including regulatory matters, creditworthiness of customers, total generating capacity available and related costs, future acquisitions and construction of generating facilities, including the impact of ITCs, and the successful remarketing of capacity as current contracts expire. Demand for electricity is partially driven by economic growth. The pace of economic growth and electricity demand may be affected by changes in regional and global economic conditions, which may impact future earnings.

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, 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. In addition, the proposed Merger will result in a combined company that is subject to various risks that do not currently impact Southern Company.

Environmental Matters

Compliance costs related to federal and state environmental statutes and regulations could affect earnings if such costs cannot continue to be fully recovered in rates on a timely basis or through market-based contracts. Environmental compliance spending over the next several years may differ materially from the amounts estimated. The timing, specific requirements, and estimated costs could change as environmental statutes and regulations are adopted or modified, as compliance plans are revised or updated, and as legal challenges to rules are completed. Further, higher costs that are recovered through regulated rates could contribute to reduced demand for electricity, which could negatively affect results of operations, cash flows, and financial condition. See Note 3 to the financial statements under "Environmental Matters" for additional information.

Environmental Statutes and Regulations

General

The electric utilities' operations are subject to extensive regulation by state and federal environmental agencies under a variety of statutes and regulations governing environmental media, including air, water, and land resources. Applicable statutes include the Clean Air Act; the Clean Water Act; the Comprehensive Environmental Response, Compensation, and Liability Act; the Resource Conservation and Recovery Act; the Toxic Substances Control Act; the Emergency Planning & Community Right-to-Know Act; the Endangered Species Act; the Migratory Bird Treaty Act; the Bald and Golden Eagle Protection Act; and related federal and state regulations. Compliance with these environmental requirements involves significant capital and operating costs, a major portion of which is expected to be recovered through existing ratemaking provisions. Through 2015, the traditional operating companies had invested approximately $11.4 billion in environmental capital retrofit projects to comply with these requirements, with annual totals of approximately $0.9 billion, $1.1 billion, and $0.7 billion for 2015, 2014, and 2013, respectively. The Southern Company system expects that capital expenditures to comply with environmental statutes and regulations will total approximately $1.8 billion from 2016 through 2018, with annual totals of approximately $0.7 billion, $0.5 billion, and $0.6 billion for 2016, 2017, and 2018, respectively. These estimated expenditures do not include any potential capital expenditures that may arise from the EPA's final rules and guidelines or subsequently approved state plans that would limit CO_2 emissions from new, existing, and modified or reconstructed fossil-fuel-fired electric generating units. See "Global Climate Issues" herein for additional information. The Southern Company system also anticipates costs associated with closure in place or by other methods, and ground water monitoring of ash ponds in accordance with the Disposal of Coal Combustion Residuals from Electric Utilities final rule (CCR Rule), which are not reflected in the capital expenditures above, as these costs are associated with the Company's asset retirement obligation (ARO) liabilities. See FINANCIAL CONDITION AND LIQUIDITY – "Capital Requirements and Contractual Obligations" herein for additional information.

The Southern Company system's ultimate environmental compliance strategy, including potential unit retirement and replacement decisions, and future environmental capital expenditures will be affected by the final requirements of new or revised environmental regulations, including the environmental regulations described below; the outcome of any legal challenges to the environmental rules; the cost, availability, and existing inventory of emissions allowances; and the fuel mix of the electric utilities. Compliance costs may arise from existing unit retirements, installation of additional environmental controls, upgrades to the transmission system, closure and monitoring of CCR facilities, and adding or changing fuel sources for certain existing units. The ultimate outcome of these matters cannot be determined at this time. See "Retail Regulatory Matters – Alabama Power – Environmental Accounting Order" and "Retail Regulatory Matters – Georgia Power – Integrated Resource Plan" herein for additional information on planned unit retirements and fuel conversions at Alabama Power and Georgia Power, respectively.

Compliance with any new federal or state legislation or regulations relating to air, water, and land resources or other environmental and health concerns could significantly affect the Company. Although new or revised environmental legislation or regulations could affect many areas of the electric utilities' operations, the full impact of any such changes cannot be determined at this time. Additionally, many of the electric utilities' commercial and industrial customers may also be affected by existing and future environmental requirements, which for some may have the potential to ultimately affect their demand for electricity.

Air Quality

Compliance with the Clean Air Act and resulting regulations has been and will continue to be a significant focus for the Southern Company system. Additional controls are currently planned or under consideration to further reduce air emissions, maintain compliance with existing regulations, and meet new requirements.

In 2012, the EPA finalized the Mercury and Air Toxics Standards (MATS) rule, which imposes stringent emissions limits for acid gases, mercury, and particulate matter on coal- and oil-fired electric utility steam generating units. The compliance deadline set by the final MATS rule was April 16, 2015, with provisions for extensions to April 16, 2016. The implementation strategy for the MATS rule includes emission controls, retirements, and fuel conversions to achieve compliance by the deadlines applicable to each unit within the Southern Company system. On June 29, 2015, the U.S. Supreme Court issued a decision finding that in developing the MATS rule the EPA had failed to properly consider costs in its decision to regulate hazardous air pollutant emissions from electric generating units. On December 15, 2015, the U.S. Court of Appeals for the District of Columbia Circuit remanded the MATS rule to the EPA without vacatur to respond to the U.S. Supreme Court's decision. The EPA's supplemental finding in response to the U.S. Supreme Court's decision, which the EPA proposes to finalize in April 2016, is not expected to have any impact on the MATS rule compliance requirements and deadlines.

The EPA regulates ground level ozone concentrations through implementation of an eight-hour ozone National Ambient Air Quality Standard (NAAQS). In 2008, the EPA adopted a revised eight-hour ozone NAAQS, and published its final area designations in 2012. The only area within the traditional operating companies' service territory designated as an ozone nonattainment area for the 2008 standard is a 15-county area within metropolitan Atlanta. On October 26, 2015, the EPA published a more stringent eight-hour ozone NAAQS. This new standard could potentially require additional emission controls, improvements in control efficiency, and operational fuel changes and could affect the siting of new generating facilities. States will recommend area designations by October 2016, and the EPA is expected to finalize them by October 2017.

The EPA regulates fine particulate matter concentrations on an annual and 24-hour average basis. All areas within the traditional operating companies' service territory have achieved attainment with the 1997 and 2006 particulate matter NAAQS and the EPA has officially redesignated former nonattainment areas within the service territory as attainment for these standards. In 2012, the EPA issued a final rule that increases the stringency of the annual fine particulate matter standard. The EPA promulgated final designations for the 2012 annual standard in December 2014, and no new nonattainment areas were designated within the traditional operating companies' service territory. The EPA has, however, deferred designation decisions for certain areas in Florida and Georgia.

Final revisions to the NAAQS for sulfur dioxide (SO_2), which established a new one-hour standard, became effective in 2010. No areas within the Southern Company system's service territory have been designated as nonattainment under this rule. However, the EPA has finalized a data requirements rule to support additional designation decisions for SO_2 in the future, which could result in nonattainment designations for areas within the Southern Company system's service territory. Implementation of the revised SO_2 standard could require additional reductions in SO_2 emissions and increased compliance and operational costs.

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

Each of the states in which the Southern Company system has fossil generation is subject to the requirements of the Cross State Air Pollution Rule (CSAPR). CSAPR is an emissions trading program that limits SO_2 and nitrogen oxide emissions from power plants in 28 states in two phases, with Phase I having begun in 2015 and Phase II beginning in 2017. On July 28, 2015, the U.S. Court of Appeals for the District of Columbia Circuit issued an opinion invalidating certain emissions budgets under the CSAPR Phase II emissions trading program for a number of states, including Alabama, Florida, Georgia, North Carolina, and Texas, but rejected all other pending challenges to the rule. The court's decision leaves the emissions trading program in place and remands the rule to the EPA for further action consistent with the court's decision. On December 3, 2015, the EPA published a proposed revision to CSAPR that would revise existing ozone-season emissions budgets for nitrogen oxide in Alabama and Mississippi and would remove Florida from the CSAPR program. The EPA proposes to finalize this rulemaking by summer 2016.

The EPA finalized regional haze regulations in 2005, with a goal of restoring natural visibility conditions in certain areas (primarily national parks and wilderness areas) by 2064. The rule involves the application of best available retrofit technology to certain sources, including fossil fuel-fired generating facilities, built between 1962 and 1977 and any additional emissions reductions necessary for each designated area to achieve reasonable progress toward the natural visibility conditions goal by 2018 and for each 10-year period thereafter.

In 2012, the EPA published proposed revisions to the New Source Performance Standard (NSPS) for Stationary Combustion Turbines (CT). If finalized as proposed, the revisions would apply the NSPS to all new, reconstructed, and modified CTs (including CTs at combined cycle units) during all periods of operation, including startup and shutdown, and alter the criteria for determining when an existing CT has been reconstructed.

On June 12, 2015, the EPA published a final rule requiring certain states (including Alabama, Florida, Georgia, Mississippi, North Carolina, and Texas) to revise or remove the provisions of their SIPs relating to the regulation of excess emissions at industrial facilities, including fossil fuel-fired generating facilities, during periods of startup, shutdown, or malfunction (SSM) by no later than November 22, 2016.

The Southern Company system has developed and continually updates a comprehensive environmental compliance strategy to assess compliance obligations associated with the current and proposed environmental requirements discussed above. As part of this strategy, certain of the traditional operating companies have developed a compliance plan for the MATS rule which includes reliance on existing emission control technologies, the construction of baghouses to provide an additional level of control on the emissions of mercury and particulates from certain generating units, the use of additives or other injection technology, the use of existing or additional natural gas capability, and unit retirements. Additionally, certain transmission system upgrades are required. The impacts of the eight-hour ozone, fine particulate matter and SO_2 NAAQS, the Alabama opacity rule, CSAPR, regional haze regulations, the MATS rule, the NSPS for CTs, and the SSM rule on the Southern Company system cannot be determined at this time and will depend on the specific provisions of the proposed and final rules, the resolution of pending and future legal challenges, and/or the development and implementation of rules at the state level. These regulations could result in significant additional capital expenditures and compliance costs that could affect future unit retirement and replacement decisions and results of operations, cash flows, and financial condition if such costs are not recovered through regulated rates or through PPAs.

In addition to the federal air quality laws described above, Georgia Power has also been subject to the requirements of the 2007 State of Georgia Multi-Pollutant Rule. The Multi-Pollutant Rule and a companion rule required reductions in emissions of mercury, SO_2, and nitrogen oxide state-wide through the installation of specified control technologies and a 95% reduction in SO_2 emissions at certain coal-fired generating units by specific dates between 2008 and 2015. In 2015, Georgia Power completed implementation of the measures necessary to comply with the Georgia Multi-Pollutant Rule at all 16 of its coal-fired generating units required to be controlled under the rule.

Water Quality

The EPA's final rule establishing standards for reducing effects on fish and other aquatic life caused by new and existing cooling water intake structures at existing power plants and manufacturing facilities became effective in October 2014. The effect of this final rule will depend on the results of additional studies and implementation of the rule by regulators based on site-specific factors. National Pollutant Discharge Elimination System permits issued after July 14, 2018 must include conditions to implement and ensure compliance with the standards and protective measures required by the rule. The ultimate impact of this rule will also depend on the outcome of ongoing legal challenges and cannot be determined at this time.

On November 3, 2015, the EPA published a final effluent guidelines rule which imposes stringent technology-based requirements for certain wastestreams from steam electric power plants. The revised technology-based limits and compliance dates will be incorporated into future renewals of National Pollutant Discharge Elimination System permits at affected units and may require the installation and operation of multiple technologies sufficient to ensure compliance with applicable new numeric wastewater compliance limits. Compliance deadlines between November 1, 2018 and December 31, 2023 will be established in permits based on information provided for each applicable wastestream. The ultimate impact of these requirements will depend on pending and any future legal challenges, compliance dates, and implementation of the final rule and cannot be determined at this time.

On June 29, 2015, the EPA and the U.S. Army Corps of Engineers jointly published a final rule revising the regulatory definition of waters of the U.S. for all Clean Water Act (CWA) programs. The final rule significantly expands the scope of federal jurisdiction under the CWA and could have significant impacts on economic development projects which could affect customer demand growth. In addition, this rule could significantly increase permitting and regulatory requirements and costs associated with the siting of new facilities and the installation, expansion, and maintenance of transmission and distribution lines. The rule became effective August 28, 2015, but on October 9, 2015, the U.S. Court of Appeals for the Sixth Circuit issued an order staying implementation of the final rule. The ultimate impact of the final rule will depend on the outcome of this and other pending legal challenges and the EPA's and the U.S. Army Corps of Engineers' field-level implementation of the rule and cannot be determined at this time.

These water quality regulations could result in significant additional capital expenditures and compliance costs that could affect future unit retirement and replacement decisions. Also, results of operations, cash flows, and financial condition could be significantly impacted if such costs are not recovered through regulated rates or through PPAs.

Coal Combustion Residuals

The traditional operating companies currently manage CCR at onsite storage units consisting of landfills and surface impoundments (CCR Units) at 22 electric generating plants. In addition to on-site storage, the traditional operating companies also sell a portion of their CCR to third parties for beneficial reuse. Individual states regulate CCR and the states in the Southern Company system's service territory each have their own regulatory requirements. Each traditional operating company has an inspection program in place to assist in maintaining the integrity of its coal ash surface impoundments.

On April 17, 2015, the EPA published the CCR Rule in the Federal Register, which became effective on October 19, 2015. The CCR Rule regulates the disposal of CCR, including coal ash and gypsum, as non-hazardous solid waste in CCR Units at active generating power plants. The CCR Rule does not automatically require closure of CCR Units but includes minimum criteria for active and inactive surface impoundments containing CCR and liquids, lateral expansions of existing units, and active landfills. Failure to meet the minimum criteria can result in the required closure of a CCR Unit. Although the EPA does not require individual states to adopt the final criteria, states have the option to incorporate the federal criteria into their state solid waste management plans in order to regulate CCR in a manner consistent with federal standards. The EPA's final rule continues to exclude the beneficial use of CCR from regulation.

Based on initial cost estimates for closure in place or by other methods, and groundwater monitoring of ash ponds pursuant to the CCR Rule, Southern Company recorded incremental AROs related to the CCR Rule. As further analysis is performed, including evaluation of the expected method of compliance, refinement of assumptions underlying the cost estimates, such as the quantities of CCR at each site, and the determination of timing, including the potential for closing ash ponds prior to the end of their currently anticipated useful life, the traditional operating companies expect to continue to periodically update these estimates. The traditional operating companies are currently completing an analysis of the plan of closure for all ash ponds in the Southern Company system, including the timing of closure and related cost recovery through regulated rates subject to the traditional operating companies' respective state PSC approval. Based on the results of that analysis, the traditional operating companies may accelerate the timing of some ash pond closures which could increase their ARO liabilities from the amounts presently recorded. The ultimate impact of the CCR Rule cannot be determined at this time and will depend on the traditional operating companies' ongoing review of the CCR Rule, the results of initial and ongoing minimum criteria assessments, and the outcome of legal challenges. Southern Company's results of operations, cash flows, and financial condition could be significantly impacted if such costs are not recovered through regulated rates. See Note 1 to the financial statements under "Asset Retirement Obligations and Other Costs of Removal" for additional information regarding Southern Company's AROs as of December 31, 2015.

Environmental Remediation

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

Global Climate Issues

On October 23, 2015, the EPA published two final actions that would limit CO_2 emissions from fossil fuel-fired electric generating units. One of the final actions contains specific emission standards governing CO_2 emissions from new, modified, and reconstructed units. The other final action, known as the Clean Power Plan, establishes guidelines for states to develop plans to meet EPA-mandated CO_2 emission rates or emission reduction goals for existing units. The EPA's final guidelines require state plans to meet interim CO_2 performance rates between 2022 and 2029 and final rates in 2030 and thereafter. At the same time, the EPA published a proposed federal plan and model rule that, when finalized, states can adopt or that would be put in place if a state either does not submit a state plan or its plan is not approved by the EPA. On February 9, 2016, the U.S. Supreme Court granted a stay of the Clean Power Plan, pending disposition of petitions for its review with the courts. The stay will remain in effect through the resolution of the litigation, whether resolved in the U.S. Court of Appeals for the District of Columbia Circuit or the U.S. Supreme Court.

These guidelines and standards could result in operational restrictions and material compliance costs, including capital expenditures, which could affect future unit retirement and replacement decisions. Southern Company's results of operations, cash flows, and financial condition could be significantly impacted if such costs are not recovered through regulated rates or through PPAs. However, the ultimate financial and operational impact of the final rules on the Southern Company system cannot be determined at this time and will depend upon numerous factors, including the Southern Company system's ongoing review of the final rules; the outcome of legal challenges, including legal challenges filed by the traditional operating companies; individual state implementation of the EPA's final guidelines, including the potential that state plans impose different standards; additional rulemaking activities in response to legal challenges and related court decisions; the impact of future changes in generation and emissions-related technology and costs; the impact of future decisions regarding unit retirement and replacement, including the type and amount of any such replacement capacity; and the time periods over which compliance will be required.

The United Nations 21st international climate change conference took place in late 2015. The result was the adoption of the Paris Agreement, which establishes a non-binding universal framework for addressing greenhouse gas emissions based on nationally determined contributions. It also sets in place a process for increasing those commitments every five years. The ultimate impact of this agreement depends on its ratification and implementation by participating countries and cannot be determined at this time.

The EPA's greenhouse gas reporting rule requires annual reporting of CO_2 equivalent emissions in metric tons for a company's operational control of facilities. Based on ownership or financial control of facilities, the Southern Company system's 2014 greenhouse gas emissions were approximately 112 million metric tons of CO_2 equivalent. The preliminary estimate of the Southern Company system's 2015 greenhouse gas emissions on the same basis is approximately 101 million metric tons of CO_2 equivalent. The level of greenhouse gas emissions from year to year will depend on the level of generation, the mix of fuel sources, and other factors.

FERC Matters

The traditional operating companies and Southern Power have authority from the FERC to sell electricity at market-based rates. Since 2008, that authority, for certain balancing authority areas, has been conditioned on compliance with the requirements of an energy auction, which the FERC found to be tailored mitigation that addresses potential market power concerns. In accordance with FERC regulations governing such authority, the traditional operating companies and Southern Power filed a triennial market power analysis in June 2014, which included continued reliance on the energy auction as tailored mitigation. On April 27, 2015, the FERC issued an order finding that the traditional operating companies' and Southern Power's existing tailored mitigation may not effectively mitigate the potential to exert market power in certain areas served by the traditional operating companies and in some adjacent areas. The FERC directed the traditional operating companies and Southern Power to show why market-based rate authority should not be revoked in these areas or to provide a mitigation plan to further address market power concerns. The traditional operating companies and Southern Power filed a request for rehearing on May 27, 2015 and on June 26, 2015 filed their response with the FERC. The ultimate outcome of this matter cannot be determined at this time.

Retail Regulatory Matters

Alabama Power

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

Rate RSE

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

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

Rate CNP

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

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

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

Environmental Accounting Order

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

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

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

Cost of Removal Accounting Order

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

Georgia Power

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

Rate Plans

In 2013, the Georgia PSC voted to approve the 2013 ARP. The 2013 ARP reflects the settlement agreement among Georgia Power, the Georgia PSC's Public Interest Advocacy Staff, and 11 of the 13 intervenors.

On December 16, 2015, in accordance with the 2013 ARP, the Georgia PSC approved an increase to tariffs effective January 1, 2016 as follows: (1) traditional base tariff rates by approximately $49 million; (2) ECCR tariff by approximately $75 million; (3) DSM tariffs by approximately $3 million; and (4) MFF tariff by approximately $13 million, for a total increase in base revenues of approximately $140 million.

Under the 2013 ARP, Georgia Power's retail ROE is set at 10.95% and earnings are evaluated against a retail ROE range of 10.00% to 12.00%. Two-thirds of any earnings above 12.00% will be directly refunded to customers, with the remaining one-third retained by Georgia Power. There will be no recovery of any earnings shortfall below 10.00% on an actual basis. In 2014, Georgia Power's retail ROE exceeded 12.00%, and Georgia Power will refund to retail customers approximately $11 million in 2016, as approved by the Georgia PSC on February 18, 2016. In 2015, Georgia Power's retail ROE was within the allowed retail ROE range.

Georgia Power is required to file a general base rate case by July 1, 2016, in response to which the Georgia PSC would be expected to determine whether the 2013 ARP should be continued, modified, or discontinued.

Integrated Resource Plan

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

To comply with the April 16, 2015 effective date of the MATS rule, Plant Branch Units 1, 3, and 4 (1,266 MWs), Plant Yates Units 1 through 5 (579 MWs), and Plant McManus Units 1 and 2 (122 MWs) were retired and operations were discontinued at Plant Mitchell Unit 3 (155 MWs) by April 15, 2015, and Plant Kraft Units 1 through 4 (316 MWs) were retired on October 13, 2015. The switch to natural gas as the primary fuel was completed at Plant Yates Units 6 and 7 by June 2015 and at Plant Gaston Units 1 through 4 by December 2015.

In the 2013 ARP, the Georgia PSC approved the amortization of the CWIP balances related to environmental projects that will not be completed at Plant Branch Units 1 through 4 and Plant Yates Units 6 and 7 over nine years ending December 2022 and the amortization of the remaining net book values of Plant Branch Unit 2 from October 2013 to December 2022, Plant Branch Unit 1 from May 2015 to December 2020, Plant Branch Unit 3 from May 2015 to December 2023, and Plant Branch Unit 4 from May 2015 to December 2024.

On January 29, 2016, Georgia Power filed its triennial IRP (2016 IRP). The filing included a request to decertify Plant Mitchell Units 3, 4A, and 4B (217 MWs) and Plant Kraft Unit 1 (17 MWs) upon approval of the 2016 IRP. The 2016 IRP also reflects that Georgia Power exercised its contractual option to sell its 33% ownership interest in the Intercession City unit (143 MWs total capacity) to Duke Energy Florida, Inc. See Note 4 to the financial statements for additional information.

In the 2016 IRP, Georgia Power requested reclassification of the remaining net book value of Plant Mitchell Unit 3, as of its retirement date, to a regulatory asset to be amortized over a period equal to the unit's remaining useful life. Georgia Power also requested that the Georgia PSC approve the deferral of the cost associated with materials and supplies remaining at the unit retirement dates to a regulatory asset, to be amortized over a period deemed appropriate by the Georgia PSC.

The decertification and retirement of these units are not expected to have a material impact on Southern Company's financial statements; however, the ultimate outcome depends on the Georgia PSC's orders in the 2016 IRP and next general base rate case.

Additionally, the 2016 IRP included a Renewable Energy Development Initiative requesting to procure up to 525 MWs of renewable resources utilizing market-based prices established through a competitive bidding process to expand Georgia Power's existing renewable initiatives, including the Advanced Solar Initiative (ASI).

A decision from the Georgia PSC on the 2016 IRP is expected in the third quarter 2016. The ultimate outcome of these matters cannot be determined at this time.

Renewables

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

In May 2014, the Georgia PSC approved Georgia Power's application for the certification of two PPAs executed in 2013 for the purchase of energy from two wind farms in Oklahoma with capacity totaling 250 MWs that will begin in 2016 and end in 2035.

As part of the Georgia Power ASI, Georgia Power executed ten PPAs that were approved by the Georgia PSC in 2014 and provide for the purchase of energy from 515 MWs of solar capacity. Two PPAs began in December 2015 and eight are expected to begin in December 2016, all of which have terms ranging from 20 to 30 years. As a result of certain acquisitions by Southern Power, Georgia Power expects that 249 MWs of the 515 MWs of contracted capacity will be purchased from solar facilities owned or under development by Southern Power.

In October 2014, the Georgia PSC approved Georgia Power's request to build, own, and operate three 30-MW solar generation facilities at three U.S. Army bases by the end of 2016. One of the three solar generation facilities began commercial operation on December 31, 2015. In addition, in December 2014, the Georgia PSC approved Georgia Power's request to build, own, and operate a 30-MW solar generation facility at Kings Bay Naval facility. On July 21, 2015, the Georgia PSC approved Georgia Power's request to build and operate an up to 46-MW solar generation facility at a U.S. Marine Corps base in Albany, Georgia. Georgia Power subsequently determined that a 31-MW facility will be constructed on the site. On December 22, 2015, the Georgia PSC approved Georgia Power's request to build and operate the remaining 15 MWs at a separate facility on the Fort Stewart Army base in Hinesville, Georgia. These facilities are expected to be operational by the end of 2016.

On April 7, 2015, the Georgia PSC approved the consolidation of four PPAs each with the same counterparty into two new PPAs with new biomass facilities. Under the terms of the order, the total 116 MWs from the existing four PPAs provided the capacity for two new PPAs of 58 MWs each. The new PPAs were executed on June 15, 2015 and November 23, 2015 and will begin in June 2017. See "Retail Regulatory Matters – Georgia Power – Integrated Resource Plan" herein for additional information on Georgia Power's renewables activities.

On April 16, 2015, the Florida PSC approved three energy purchase agreements totaling 120 MWs of utility-scale solar generation located at three military installations in northwest Florida. Purchases under these solar agreements are expected to begin by early 2017. On May 5, 2015, the Florida PSC approved an energy purchase agreement for up to 178 MWs of wind generation in central Oklahoma. Purchases under these agreements began in January 2016, are for energy only, and will be recovered through Gulf Power's fuel cost recovery mechanism.

On November 10, 2015, the Mississippi PSC issued three separate orders approving three solar facilities for a combined total of approximately 105 MWs. Mississippi Power will purchase all of the energy produced by the solar facilities for the 25-year term of the contracts under three PPAs, two of which have been finalized and one of which remains under negotiation. The projects are expected to be in service by the end of 2016 and the resulting energy purchases will be recovered through Mississippi Power's fuel cost recovery mechanism.

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

Retail Fuel Cost Recovery

The traditional 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 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. During 2015, each of the traditional operating companies filed requests with their respective state PSCs for fuel rate decreases. Upon approval of these requests, each of the traditional operating companies decreased fuel rates in January 2016.

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

Construction Program

Overview

The subsidiary companies of Southern Company are engaged in continuous construction programs to accommodate existing and estimated future loads on their respective systems. The Southern Company system intends to continue its strategy of developing and constructing new generating facilities, as well as adding or changing fuel sources for certain existing units, adding environmental control equipment, and expanding the transmission and distribution systems. For the traditional 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. The construction programs of the traditional operating companies and Southern Power are currently estimated to include an investment of approximately $7.3 billion, $5.2 billion, and $5.5 billion for 2016, 2017, and 2018, respectively.

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

Also see FINANCIAL CONDITION AND LIQUIDITY – "Capital Requirements and Contractual Obligations" herein for additional information regarding Southern Company's capital requirements for its subsidiaries' construction programs.

Integrated Coal Gasification Combined Cycle

Mississippi Power's current cost estimate for the Kemper IGCC in total is approximately $6.63 billion, which includes approximately $5.29 billion of costs subject to the construction cost cap. Mississippi Power does not intend to seek any rate recovery for any related costs that exceed the $2.88 billion cost cap, net of the DOE Grants and excluding the Cost Cap Exceptions. In the aggregate, the Company has incurred charges of $2.41 billion ($1.5 billion after tax) as a result of changes in the cost estimate above the cost cap for the Kemper IGCC through December 31, 2015. Mississippi Power's current cost estimate includes costs through August 31, 2016. In subsequent periods, any further changes in the estimated costs to complete construction of the Kemper IGCC subject to the $2.88 billion cost cap, net of the DOE Grants and excluding the Cost Cap Exceptions, will be reflected in the Company's statements of income and these changes could be material.

During 2015, events related to the Kemper IGCC had a significant adverse impact on Mississippi Power's financial condition. These events include (i) the termination by SMEPA in May 2015 of the APA between Mississippi Power and SMEPA, whereby SMEPA previously agreed to purchase a 15% undivided interest in the Kemper IGCC, and Mississippi Power's subsequent return of approximately $301 million, including interest, to SMEPA; (ii) the termination of Mirror CWIP rates in July 2015 and the refund of $371 million in Mirror CWIP rate collections, including carrying costs, in the fourth quarter 2015 as a result of the Mississippi Supreme Court's reversal of the Mississippi PSC's 2013 rate order authorizing the collection of $156 million annually in Mirror CWIP rates; and (iii) the required recapture in December 2015 of $235 million of Internal Revenue Code of 1986, as amended (Internal Revenue Code), Section 48A (Phase II) tax credits as a result of the extension of the expected in-service date for the Kemper IGCC.

As a result of the termination of the Mirror CWIP rates, Mississippi Power submitted a filing to the Mississippi PSC requesting interim rates to collect approximately $159 million annually until a final rate decision could be made on Mississippi Power's request to recover costs associated with Kemper IGCC assets that had been placed in service. The Mississippi PSC approved the implementation of the requested interim rates in August 2015. Subsequently, on December 3, 2015, the Mississippi PSC issued an order (In-Service Asset Rate Order), based on a stipulation between Mississippi Power and the MPUS, authorizing Mississippi Power to replace the interim rates with rates that provide for the recovery of approximately $126 million annually related to Kemper IGCC assets previously placed in service. Further proceedings related to cost recovery for the Kemper IGCC are expected after the remainder of the Kemper IGCC is placed in service, which is currently expected in the third quarter 2016. On February 25, 2016, Greenleaf CO2 Solutions, LLC filed a notice of appeal of the In-Service Asset Rate Order with the Mississippi Supreme Court. Mississippi Power believes the appeal has no merit; however, an adverse outcome in this appeal could have a material impact on Southern Company's results of operations.

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

Nuclear Construction

On December 31, 2015, Westinghouse Electric Company LLC (Westinghouse) and Georgia Power, Oglethorpe Power Corporation, the Municipal Electric Authority of Georgia, and the City of Dalton, Georgia, acting by and through its Board of Water, Light, and Sinking Fund Commissioners, doing business as Dalton Utilities (collectively, Vogtle Owners), entered into a definitive settlement agreement (Contractor Settlement Agreement) to resolve disputes between the Vogtle Owners and Westinghouse and Stone & Webster, Inc., a subsidiary of The Shaw Group Inc., which was acquired by Chicago Bridge & Iron Company N.V. (CB&I) (Westinghouse and Stone & Webster, Inc., collectively, Contractor) under the engineering, procurement, and construction agreement between the Vogtle Owners and the Contractor (Vogtle 3 and 4 Agreement), including the pending litigation between the Vogtle Owners and the Contractor (Vogtle Construction Litigation).

Effective December 31, 2015, Georgia Power, acting for itself and as agent for the other Vogtle Owners, and the Contractor entered into an amendment to the Vogtle 3 and 4 Agreement to implement the Contractor Settlement Agreement. The Contractor Settlement Agreement and the related amendment to the Vogtle 3 and 4 Agreement (i) restrict the Contractor's ability to seek further increases in the contract price by clarifying and limiting the circumstances that constitute nuclear regulatory changes in law; (ii) provide for enhanced dispute resolution procedures; (iii) revise the guaranteed substantial completion dates to match the current estimated in-service dates of June 30, 2019 for Unit 3 and June 30, 2020 for Unit 4; (iv) provide that delay liquidated damages will now commence from the current estimated nuclear fuel loading date for each unit, which is December 31, 2018 for Unit 3 and December 31, 2019 for Unit 4, rather than the original guaranteed substantial completion dates under the Vogtle 3 and 4 Agreement; and (v) provide that Georgia Power, based on its ownership interest, will pay to the Contractor and capitalize to the project cost approximately $350 million, of which approximately $120 million has been paid previously under the dispute resolution procedures of the Vogtle 3 and 4 Agreement. Further, subsequent to December 31, 2015, Georgia Power paid approximately $121 million under the terms of the Contractor Settlement Agreement. In addition, the Contractor Settlement Agreement provides for the resolution of other open existing items relating to the scope of the project under the Vogtle 3 and 4 Agreement, including cyber security, for which costs were reflected in Georgia Power's previously disclosed in-service cost estimate.

Further, as part of the settlement: (i) Westinghouse has engaged Fluor Enterprises, Inc., a subsidiary of Fluor Corporation, as a new construction subcontractor; and (ii) the Vogtle Owners, CB&I, and The Shaw Group Inc. have entered into mutual releases of any and all claims arising out of events or circumstances in connection with the construction of Plant Vogtle Units 3 and 4 that occurred on or before the date of the Contractor Settlement Agreement. On January 5, 2016, the Vogtle Construction Litigation was dismissed with prejudice.

On January 21, 2016, Georgia Power submitted the Contractor Settlement Agreement and the related amendment to the Vogtle 3 and 4 Agreement to the Georgia PSC for its review. On February 2, 2016, the Georgia PSC ordered Georgia Power to file supplemental information by April 5, 2016 in support of the Contractor Settlement Agreement and Georgia Power's position that all construction costs to date have been prudently incurred and that the current estimated in-service capital cost and schedule are reasonable. Following Georgia Power's filing under the order, the Georgia PSC Staff (Staff) will conduct a review of all costs incurred related to Plant Vogtle Units 3 and 4, the schedule for completion of Plant Vogtle Units 3 and 4, and the Contractor Settlement Agreement and the Staff is authorized to engage in related settlement discussions with Georgia Power and any intervenors. The order provides that the Staff is required to report to the Georgia PSC by October 5, 2016 with respect to the status of its review and any settlement-related negotiations.

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

Income Tax Matters

Bonus Depreciation

On December 18, 2015, the Protecting Americans from Tax Hikes (PATH) Act was signed into law. Bonus depreciation was extended for qualified property placed in service over the next five years. The PATH Act allows for 50% bonus depreciation for 2015, 2016, and 2017; 40% bonus depreciation for 2018; and 30% bonus depreciation for 2019 and certain long-lived assets placed in service in 2020. The extension of 50% bonus depreciation is expected to result in approximately $855 million of positive cash flows for the 2015 tax year and approximately $1.3 billion for the 2016 tax year, which may not all be realized in 2016 due to a projected net operating loss for the 2016 tax year. Approximately $360 million of this benefit is dependent upon placing the remainder of the Kemper IGCC in service in 2016. See Note 3 to the financial statements under "Integrated Coal Gasification Combined Cycle" for additional information. The ultimate outcome of this matter cannot be determined at this time.

Tax Credits

The IRS allocated $279 million (Phase II) of Internal Revenue Code Section 48A tax credits to Mississippi Power in connection with the Kemper IGCC. These tax credits were dependent upon meeting the IRS certification requirements, including an in-service date no later than April 19, 2016 and the capture and sequestration (via enhanced oil recovery) of at least 65% of the CO_2 produced by the Kemper IGCC during operations in accordance with the Internal Revenue Code. As a result of the schedule extension for the Kemper IGCC, the Phase II credits have been recaptured. See Note 3 to the financial statements under "Integrated Coal Gasification Combined Cycle" for additional information.

In 2009, President Obama signed into law the American Recovery and Reinvestment Act of 2009 (ARRA). Major tax incentives in the ARRA included renewable energy incentives. The PATH Act extended the ITC with a phase out that 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 the permanent 10% ITC for solar projects that commence construction on or after January 1, 2022. In addition, the PATH Act extended the production tax credit (PTC) for wind projects with a phase out that allows for 100% PTC for wind projects that commence construction in 2016; 80% PTC for wind projects that commence construction in 2017; 60% PTC for wind projects that commence construction in 2018; and 40% PTC for wind projects that commence construction in 2019. The Company has received ITCs and PTCs in connection with investments in solar, wind, and biomass facilities at Southern Power and Georgia Power. See Note 1 to the financial statements under "Income and Other Taxes" for additional information regarding credits amortized and the tax benefit related to basis differences.

Section 174 Research and Experimental Deduction

Southern Company reflected deductions for research and experimental (R&E) expenditures related to the Kemper IGCC in its federal income tax calculations for 2013, 2014, and 2015. In May 2015, Southern Company amended its 2008 through 2013 federal income tax returns to include deductions for Kemper IGCC-related R&E expenditures. Due to the uncertainty related to this tax position, Southern Company had unrecognized tax benefits associated with these R&E deductions totaling approximately $423 million as of December 31, 2015. See Note 5 to the financial statements under "Unrecognized Tax Benefits" for additional information. Also see "Bonus Depreciation" herein. The ultimate outcome of this matter cannot be determined at this time.

Other Matters

Southern Company and its subsidiaries are involved in various other matters being litigated and regulatory matters that could affect future earnings. In addition, Southern Company and its subsidiaries are subject to certain claims and legal actions arising in the ordinary course of business. The business activities of Southern Company's subsidiaries are subject to extensive governmental regulation related to public health and the environment, such as regulation of air emissions and water discharges. Litigation over environmental issues and claims of various types, including property damage, personal injury, common law nuisance, and citizen enforcement of environmental requirements, such as air quality and water standards, has occurred throughout the U.S. This litigation has included claims for damages alleged to have been caused by CO_2 and other emissions, CCR, and alleged exposure to hazardous materials, and/or requests for injunctive relief in connection with such matters.

The ultimate outcome of such pending or potential litigation against Southern Company and its subsidiaries cannot be predicted at this time; however, for current proceedings not specifically reported herein or in Note 3 to the financial statements, management does not anticipate that the ultimate liabilities, if any, arising from such current proceedings would have a material effect on Southern Company's financial statements. See Note 3 to the financial statements for a discussion of various other contingencies, regulatory matters, and other matters being litigated which may affect future earnings potential.

Through 2015, capacity revenues represented the majority of Gulf Power's wholesale earnings. Gulf Power had long-term sales contracts to cover 100% of its ownership share of Plant Scherer Unit 3 (205 MWs) and these capacity revenues represented 82% of Gulf Power's total wholesale capacity revenues for 2015. Due to the expiration of a wholesale contract at the end of 2015 and future expiration dates of the remaining wholesale contracts for the unit, Gulf Power currently has contracts to cover 34% of the unit for 2016 and 27% of the unit through 2019. Gulf Power is actively evaluating alternatives relating to this asset, including replacement wholesale contracts. The expiration of the contract in 2015 and the scheduled future expiration of the remaining contracts are not expected to have a material impact on Southern Company's earnings. In the event some portion of the Gulf Power's ownership of Plant Scherer Unit 3 is not subject to a replacement long-term wholesale contract, the proportionate amount of the unit may be sold into the Southern Company power pool or into the wholesale market. The ultimate outcome of this matter cannot be determined at this time.

ACCOUNTING POLICIES

Application of Critical Accounting Policies and Estimates

Southern Company prepares its consolidated financial statements in accordance with GAAP. Significant accounting policies are described in Note 1 to the financial statements. In the application of these policies, certain estimates are made that may have a material impact on Southern Company's results of operations and related disclosures. Different assumptions and measurements could produce estimates that are significantly different from those recorded in the financial statements. Senior management has reviewed and discussed the following critical accounting policies and estimates with the Audit Committee of Southern Company's Board of Directors.

Electric Utility Regulation

Southern Company's traditional operating companies, which comprised approximately 94% of Southern Company's total operating revenues for 2015, are subject to retail regulation by their respective state PSCs and wholesale regulation by the FERC. These regulatory agencies set the rates the traditional operating companies are permitted to charge customers based on allowable costs, including a reasonable ROE. As a result, the traditional operating companies apply accounting standards which require the financial statements to reflect the effects of rate regulation. Through the ratemaking process, the regulators may require the inclusion of costs or revenues in periods different than when they would be recognized by a non-regulated company. This treatment may result in the deferral of expenses and the recording of related regulatory assets based on anticipated future recovery through rates or the deferral of gains or creation of liabilities and the recording of related regulatory liabilities. The application of the accounting standards has a further effect on the Company's financial statements as a result of the estimates of allowable costs used in the ratemaking process. These estimates may differ from those actually incurred by the traditional operating companies; therefore, the accounting estimates inherent in specific costs such as depreciation, AROs, and pension and postretirement benefits have less of a direct impact on the Company's results of operations and financial condition than they would on a non-regulated company.

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

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

During 2015, Mississippi Power further revised its cost estimate to complete construction and start-up of the Kemper IGCC to an amount that exceeds the $2.88 billion cost cap, net of the DOE Grants and excluding the Cost Cap Exceptions. Mississippi Power does not intend to seek any rate recovery for any costs related to the construction of the Kemper IGCC that exceed the $2.88 billion cost cap, net of the DOE Grants and excluding the Cost Cap Exceptions.

As a result of the revisions to the cost estimate, Southern Company recorded total pre-tax charges to income for the estimated probable losses on the Kemper IGCC of $183 million ($113 million after tax) in the fourth quarter 2015, $150 million ($93 million after tax) in the third quarter 2015, $23 million ($14 million after tax) in the second quarter 2015, $9 million ($6 million after tax) in the first quarter 2015, $70 million ($43 million after tax) in the fourth quarter 2014, $418 million ($258 million after tax) in the third quarter 2014, $380 million ($235 million after tax) in the first quarter 2014, $40 million ($25 million after tax) in the fourth quarter 2013, $150 million ($93 million after tax) in the third quarter 2013, $450 million ($278 million after tax) in the second quarter 2013, and $540 million ($333 million after tax) in the first quarter 2013. In the aggregate, Southern Company has incurred charges of $2.4 billion ($1.5 billion after tax) as a result of changes in the cost estimate above the cost cap for the Kemper IGCC through December 31, 2015.

Mississippi Power has experienced, and may continue to experience, material changes in the cost estimate for the Kemper IGCC. In subsequent periods, any further changes in the estimated costs to complete construction and start-up of the Kemper IGCC subject to the $2.88 billion cost cap, net of the DOE Grants and excluding the Cost Cap Exceptions, will be reflected in Southern Company's statements of income and these changes could be material. Any further cost increases and/or extensions of the in-service date with respect to the Kemper IGCC may result from factors including, but not limited to, labor costs and productivity, adverse weather conditions, shortages and inconsistent quality of equipment, materials, and labor, contractor or supplier delay, non-performance under operating or other agreements, operational readiness, including specialized operator training and required site safety programs, unforeseen engineering or design problems, start-up activities for this first-of-a-kind technology (including major equipment failure and system integration), and/or operational performance (including, but not limited to, additional costs to satisfy any operational parameters ultimately adopted by the Mississippi PSC).

Mississippi Power's revised cost estimate includes costs through August 31, 2016. Any extension of the in-service date beyond August 31, 2016 is currently estimated to result in additional base costs of approximately $25 million to $35 million per month, which includes maintaining necessary levels of start-up labor, materials, and fuel, as well as operational resources required to execute start-up and commissioning activities. However, additional costs may be required for remediation of any further equipment and/or design issues identified. Any extension of the in-service date with respect to the Kemper IGCC beyond August 31, 2016 would also increase costs for the Cost Cap Exceptions, which are not subject to the $2.88 billion cost cap established by the Mississippi PSC. These costs include AFUDC, which is currently estimated to total approximately $13 million per month, as well as carrying costs and operating expenses on Kemper IGCC assets placed in service and consulting and legal fees of approximately $2 million per month.

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

Asset Retirement Obligations

AROs are computed as the fair value of the estimated ultimate costs for an asset's future retirement and are recorded in the period in which the liability is incurred. The costs are capitalized as part of the related long-lived asset and depreciated over the asset's useful life. In the absence of quoted market prices, AROs are estimated using present value techniques in which estimates of future cash outlays associated with the asset retirements are discounted using a credit-adjusted risk-free rate. Estimates of the timing and amounts of future cash outlays are based on projections of when and how the assets will be retired and the cost of future removal activities.

The liability for AROs primarily relates to 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 – and facilities that are subject to the CCR Rule, principally ash ponds. In addition, the Southern Company system has retirement obligations related to various landfill sites, asbestos removal, mine reclamation, and disposal of polychlorinated biphenyls in certain transformers. The Southern Company system also has identified retirement obligations related to certain transmission and distribution facilities, certain wireless communication towers, property associated with the Southern Company system's rail lines and natural gas pipelines, and certain structures authorized by the U.S. Army Corps of Engineers. However, liabilities for the removal of these assets have not been recorded because the settlement timing for the retirement obligations related to these assets is indeterminable and, therefore, the fair value of the retirement obligations cannot be reasonably estimated. A liability for these AROs will be recognized when sufficient information becomes available to support a reasonable estimation of the ARO.

As a result of the final CCR Rule discussed above, Alabama Power, Gulf Power, and Mississippi Power recorded new AROs for facilities that are subject to the CCR Rule. Georgia Power had previously recorded AROs as a result of state requirements in Georgia which closely align with the requirements of the CCR Rule. The cost estimates are based on information using various assumptions related to closure and post-closure costs, timing of future cash outlays, inflation and discount rates, and the potential methods for complying with the CCR Rule requirements for closure in place or by other methods. As further analysis is performed, including evaluation of the expected method of compliance, refinement of assumptions underlying the cost estimates, such as the quantities of CCR at each site, and the determination of timing, including the potential for closing ash ponds prior to the end of their currently anticipated useful life, the traditional operating companies expect to continue to periodically update these estimates.

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

See Note 1 to the financial statements under "Asset Retirement Obligations and Other Costs of Removal" and "Nuclear Decommissioning" for additional information.

Pension and Other Postretirement Benefits

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

Key elements in determining Southern Company's pension and other postretirement benefit expense are the expected long-term return on plan assets and the discount rate used to measure the benefit plan obligations and the periodic benefit plan expense for future periods. The expected long-term return on pension and other postretirement benefit plan assets is based on Southern Company's investment strategy, historical experience, and expectations for long-term rates of return that consider external actuarial advice. Southern Company determines the long-term return on plan assets by applying the long-term rate of expected returns on various asset classes to Southern Company's target asset allocation. For purposes of determining its liability related to the pension and other postretirement benefit plans, Southern Company discounts the future related cash flows using a single-point discount rate for each plan developed from the weighted average of market-observed yields for high quality fixed income securities with maturities that correspond to expected benefit payments. For 2015 and prior years, Southern Company computed the interest cost component of its net periodic pension and other postretirement benefit plan expense using the same single-point discount rate. For 2016, Southern Company has adopted a full yield curve approach for calculating the interest cost component whereby the discount rate for each year is applied to the liability for that specific year. As a result, the interest cost component of net periodic pension and other postretirement benefit plan expense will decrease by approximately $96 million in 2016.

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

Change in Assumption	Increase/(Decrease) in Total Benefit Expense for 2016	Increase/(Decrease) in Projected Obligation for Pension Plan at December 31, 2015	Increase/(Decrease) in Projected Obligation for Other Postretirement Benefit Plans at December 31, 2015
		(in millions)	
25 basis point change in discount rate	$30/$(29)	$353/$(335)	$56/$(53)
25 basis point change in salaries	$12/$(11)	$91/$(88)	$–/$–
25 basis point change in long-term return on plan assets	$25/$(25)	N/A	N/A

N/A – Not applicable

Contingent Obligations

Southern Company is subject to a number of federal and state laws and regulations as well as other factors and conditions that subject it to environmental, litigation, income tax, and other risks. See FUTURE EARNINGS POTENTIAL herein and Note 3 to the financial statements for more information regarding certain of these contingencies. Southern Company periodically evaluates its exposure to such risks and records reserves for those matters where a non-tax-related loss is considered probable and reasonably estimable and records a tax asset or liability if it is more likely than not that a tax position will be sustained. The adequacy of reserves can be significantly affected by external events or conditions that can be unpredictable; thus, the ultimate outcome of such matters could materially affect Southern Company's results of operations, cash flows, or financial condition.

Recently Issued Accounting Standards

The Financial Accounting Standards Board's (FASB) ASC 606, *Revenue from Contracts with Customers*, revises the accounting for revenue recognition effective for fiscal years beginning after December 15, 2017. Southern Company continues to evaluate the requirements of ASC 606. The ultimate impact of the new standard has not yet been determined.

On April 7, 2015, the FASB issued Accounting Standards Update (ASU) No. 2015-03, *Interest – Imputation of Interest (Subtopic 835-30): Simplifying the Presentation of Debt Issuance Costs* (ASU 2015-03). ASU 2015-03 requires that debt issuance costs related to a recognized debt liability be presented in the balance sheet as a direct deduction from the carrying amount of that debt liability and is effective for fiscal years beginning after December 15, 2015. As permitted, Southern Company elected to early adopt the guidance as of December 31, 2015 and applied its provisions retrospectively to each prior period presented for comparative purposes. The new guidance resulted in an adjustment to the presentation of debt issuance costs as an offset to the related debt balances primarily in long-term debt totaling $202 million as of December 31, 2014. These debt issuance costs were previously presented within unamortized debt issuance expense. Other than the reclassification, the adoption of ASU 2015-03 did not have an impact on the results of operations, cash flows, or financial condition of Southern Company. See Notes 6 and 10 to the financial statements for disclosures impacted by ASU 2015-03.

On May 1, 2015, the FASB issued ASU No. 2015-07, *Fair Value Measurement (Topic 820): Disclosures for Investments in Certain Entities That Calculate Net Asset Value per Share (or Its Equivalent)* (ASU 2015-07), effective for fiscal years beginning after December 15, 2015. As permitted, Southern Company elected to early adopt the guidance as of December 31, 2015 and applied its provisions retrospectively to each prior period presented for comparative purposes. The amendments in ASU 2015-07 remove the requirement to categorize within the fair value hierarchy all investments for which fair value is measured using the net asset value per share practical expedient. In addition, the amendments remove the requirement to make certain disclosures for all investments that are eligible to be measured at fair value using the net asset value per share practical expedient regardless of whether the practical expedient was used. In accordance with ASU 2015-07, previously reported amounts have been conformed to the current presentation. The adoption of ASU 2015-07 had no impact on the results of operations, cash flows, or financial condition of Southern Company. See Notes 2 and 10 to the financial statements for disclosures impacted by ASU 2015-07.

On November 20, 2015, the FASB issued ASU No. 2015-17, *Income Taxes (Topic 740): Balance Sheet Classification of Deferred Taxes* (ASU 2015-17), which simplifies the presentation of deferred income taxes. ASU 2015-17 requires deferred tax assets and liabilities to be presented as non-current in a classified balance sheet and is effective for fiscal years beginning after December 15, 2016, including interim periods within that reporting period. As permitted, Southern Company elected to early adopt the guidance as of December 31, 2015 and applied its provisions retrospectively to each prior period presented for comparative purposes. Prior to the adoption of ASU 2015-17, all deferred income tax assets and liabilities were required to be separated into current and non-current amounts. The new guidance resulted in a reclassification from deferred income taxes, current of $506 million, with $488 million to non-current accumulated deferred income taxes and $18 million to other deferred charges, as well as $2 million from accrued income taxes to non-current accumulated deferred income taxes in Southern Company's December 31, 2014 balance sheet. Other than the reclassification, the adoption of ASU 2015-17 did not have an impact on the results of operations, cash flows, or financial condition of Southern Company. See Note 5 to the financial statements for disclosures impacted by ASU 2015-17.

FINANCIAL CONDITION AND LIQUIDITY

Overview

Earnings in 2015 and 2014 were negatively affected by revisions to the cost estimate for the Kemper IGCC; however, Southern Company's financial condition remained stable at December 31, 2015 and December 31, 2014. Through December 31, 2015, Southern Company has incurred non-recoverable cash expenditures of $1.95 billion and is expected to incur approximately $0.46 billion in additional non-recoverable cash expenditures through completion of the Kemper IGCC.

Southern Company's cash requirements primarily consist of funding ongoing operations, funding the cash consideration for the Merger, 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, to maintain existing facilities, to comply with environmental regulations, 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 2016 through 2018, Southern Company's projected common stock dividends, capital expenditures, and debt maturities are expected to exceed operating cash flows. The Southern Company system's projected capital expenditures in that period include investments to build new generation facilities, to maintain existing generation facilities, to add environmental modifications to existing generating units, to add or change fuel sources for certain existing units, and to expand and improve transmission and distribution facilities. Southern Company plans to finance future cash needs in excess of its operating cash flows primarily by accessing borrowings from financial institutions and through debt and equity issuances in the capital markets. Southern Company intends to continue to monitor its access to short-term and long-term capital markets as well as bank credit arrangements to meet future capital and liquidity needs. See FUTURE EARNINGS POTENTIAL – "Income Tax Matters – Bonus Depreciation" and "Sources of Capital," "Financing Activities," and "Capital Requirements and Contractual Obligations" herein for additional information.

Southern Company's investments in the qualified pension plan and the nuclear decommissioning trust funds decreased in value as of December 31, 2015 as compared to December 31, 2014. No contributions to the qualified pension plan were made for the year ended December 31, 2015, and no mandatory contributions to the qualified pension plan are anticipated during 2016. See "Contractual Obligations" herein and Notes 1 and 2 to the financial statements under "Nuclear Decommissioning" and "Pension Plans," respectively, for additional information.

Net cash provided from operating activities in 2015 totaled $6.3 billion, an increase of $459 million from 2014. The increase in net cash provided from operating activities was primarily due to an increase in fuel cost recovery, partially offset by the timing of vendor payments. Net cash provided from operating activities in 2014 totaled $5.8 billion, a decrease of $282 million from 2013. Significant changes in operating cash flow for 2014 as compared to 2013 included $500 million of voluntary contributions to the qualified pension plan and an increase in receivables due to under recovered fuel costs, partially offset by an increase in accrued compensation.

Net cash used for investing activities in 2015, 2014, and 2013 totaled $7.3 billion, $6.4 billion, and $5.7 billion, respectively. The cash used for investing activities in each of these years was primarily due to gross property additions for installation of equipment to comply with environmental standards, construction of generation, transmission, and distribution facilities, acquisitions of solar facilities, and purchases of nuclear fuel.

Net cash provided from financing activities totaled $1.7 billion in 2015 due to issuances of long-term debt and common stock and an increase in short-term debt, partially offset by common stock dividend payments and redemptions of long-term debt and preferred and preference stock. Net cash provided from financing activities totaled $644 million in 2014 due to issuances of long-term debt and common stock, partially offset by common stock dividend payments, redemptions of long-term debt, and a reduction in short-term debt. Net cash used for financing activities totaled $324 million in 2013 due to redemptions of long-term debt and payments of common stock dividends, partially offset by issuances of long-term debt and common stock and an increase in notes payable. Fluctuations in cash flow from financing activities vary from year to year based on capital needs and the maturity or redemption of securities.

Significant balance sheet changes in 2015 included increases of $4.9 billion in plant in service, net of depreciation and $1.3 billion in construction work in progress for the installation of equipment to comply with environmental standards and construction of generation, transmission, and distribution facilities; increases of $0.7 billion in other regulatory assets, deferred and $1.6 billion in AROs primarily resulting from impacts of the CCR Rule; an increase of $3.4 billion in short-term and long-term debt to fund the subsidiaries' continuous construction programs and for other general corporate purposes; and an increase of $1.2 billion in accumulated deferred income taxes primarily as a result of bonus depreciation. See Note 1 and Note 5 to the financial statements for additional information regarding AROs and deferred income taxes, respectively.

At the end of 2015, the market price of Southern Company's common stock was $46.79 per share (based on the closing price as reported on the New York Stock Exchange) and the book value was $22.59 per share, representing a market-to-book value ratio of 207%, compared to $49.11, $21.98, and 223%, respectively, at the end of 2014.

Sources of Capital

Southern Company intends to meet its future capital needs through operating cash flows, short-term debt, term loans, and external security issuances. Equity capital can be provided from any combination of the Company's stock plans, private placements, or public offerings. The amount and timing of additional equity capital and debt issuances in 2016, as well as in subsequent years, will be contingent on Southern Company's investment opportunities and the Southern Company system's capital requirements.

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

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

Eligible Project Costs incurred through December 31, 2015 would allow for borrowings of up to $2.3 billion under the FFB Credit Facility, of which Georgia Power has borrowed $2.2 billion.

Mississippi Power received $245 million of DOE Grants in prior years that were used for the construction of the Kemper IGCC. An additional $25 million of DOE Grants is expected to be received for the commercial operation of the Kemper IGCC. See Note 3 to the financial statements under "Integrated Coal Gasification Combined Cycle" for information regarding legislation related to the securitization of certain costs of the Kemper IGCC.

Mississippi Power expects the Kemper IGCC to qualify for additional DOE grants included in the recently passed Consolidated Appropriations Act of 2015, which are expected to be used to reduce future rate impacts for customers. The ultimate outcome of this matter cannot be determined at this time.

The issuance of securities by the traditional operating companies is generally subject to the approval of the applicable state PSC. 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 operating company, and Southern Power obtain financing separately without credit support from any affiliate. See Note 6 to the financial statements under "Bank Credit Arrangements" for additional information. The Southern Company system does not maintain a centralized cash or money pool. Therefore, funds of each company are not commingled with funds of any other company in the Southern Company system.

As of December 31, 2015, Southern Company's current liabilities exceeded current assets by $2.6 billion, primarily due to long-term debt that is due within one year of $2.7 billion, including approximately $0.5 billion at the parent company, $0.2 billion at Alabama Power, $0.7 billion at Georgia Power, $0.1 billion at Gulf Power, $0.7 billion at Mississippi Power, and $0.4 billion at Southern Power. In addition, Mississippi Power has $0.5 billion in short-term bank loans scheduled to mature on April 1, 2016. To meet short-term cash needs and contingencies, Southern Company has substantial cash flow from operating activities and access to capital markets and financial institutions. Southern Company, the traditional operating companies, and Southern Power 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 operating companies and Southern Power, equity contributions and/or loans from Southern Company to meet their short-term capital needs.

The financial condition of Mississippi Power and its ability to obtain financing needed for normal business operations and completion of construction and start-up of the Kemper IGCC were adversely affected by the return of approximately $301 million of interest bearing refundable deposits to SMEPA in June 2015 in connection with the termination of the APA, the required refund of approximately $371 million of Mirror CWIP rate collections, including associated carrying costs, the termination of the Mirror CWIP rate, and the required recapture of Phase II tax credits. On December 3, 2015, the Mississippi PSC approved the In-Service Asset Rate Order which, among other things, provides for retail rate recovery of an annual revenue requirement of approximately $126 million which became effective on December 17, 2015. Mississippi Power plans to refinance its 2016 debt maturities with bank term loans and to obtain the funds required for construction and other purposes from operating cash flows and lines of credit (to the extent available) as well as loans and, under certain circumstances, equity contributions from Southern Company. See Note 3 to the financial statements under "Integrated Coal Gasification Combined Cycle" herein for additional information.

At December 31, 2015, Southern Company and its subsidiaries had approximately $1.4 billion of cash and cash equivalents. Committed credit arrangements with banks at December 31, 2015 were as follows:

	Expires						Executable Term Loans		Due Within One Year	
Company	**2016**	**2017**	**2018**	**2020**	**Total**	**Unused**	**One Year**	**Two Years**	**Term Out**	**No Term Out**
		(in millions)			*(in millions)*		*(in millions)*		*(in millions)*	
Southern Company[(a)]	$ —	$ —	$ 1,000	$ 1,250	$ 2,250	$ 2,250	$ —	$ —	$ —	$ —
Alabama Power	40	—	500	800	1,340	1,340	—	—	—	40
Georgia Power	—	—	—	1,750	1,750	1,732	—	—	—	—
Gulf Power	80	30	165	—	275	275	50	—	50	30
Mississippi Power	220	—	—	—	220	195	30	15	45	175
Southern Power[(b)]	—	—	—	600	600	566	—	—	—	—
Other	70	—	—	—	70	70	—	—	—	70
Total	$ 410	$ 30	$ 1,665	$ 4,400	$ 6,505	$ 6,428	$ 80	$ 15	$ 95	$ 315

(a) Excludes the $8.1 billion Bridge Agreement entered into in September 2015 that will be funded only to the extent necessary to provide financing for the Merger as discussed herein.

(b) Excludes credit agreements (Project Credit Facilities) assumed with the acquisition of certain solar facilities, which are non-recourse to Southern Power Company, the proceeds of which are being used to finance project costs related to such solar facilities currently under construction. See Note 12 to the financial statements under "Southern Power" for additional information.

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

As reflected in the table above, in August 2015, Southern Company, Alabama Power, Georgia Power, and Southern Power Company each amended and restated their multi-year credit arrangements, which, among other things, extended the maturity dates from 2018 to 2020. Southern Company and Southern Power Company increased their borrowing ability under these arrangements to $1.25 billion from $1.0 billion and to $600 million from $500 million, respectively. Georgia Power increased its borrowing ability by $150 million under its facility maturing in 2020 and terminated its aggregate $150 million facilities maturing in 2016. In September 2015, Southern Company entered into an additional multi-year credit arrangement for $1 billion with a maturity date of 2018. Also in September 2015, Alabama Power entered into a new $500 million three-year credit arrangement which replaced a majority of Alabama Power's bilateral credit arrangements. In November 2015, Gulf Power amended and restated certain of its multi-year credit arrangements which, among other things, extended the maturity dates from 2016 to 2018.

Most of these bank credit arrangements 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. Southern Company, the traditional operating companies, and Southern Power Company are currently in compliance with all such covenants. None of the bank credit arrangements contain material adverse change clauses at the time of borrowings.

Subject to applicable market conditions, 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 traditional operating companies' pollution control revenue bonds and commercial paper programs. The amount of variable rate pollution control revenue bonds outstanding requiring liquidity support as of December 31, 2015 was approximately $1.8 billion. In addition, at December 31, 2015, the traditional operating companies had approximately $181 million of fixed rate pollution control revenue bonds outstanding that were required to be remarketed within the next 12 months.

Southern Company intends to initially fund the cash consideration for the Merger using a mix of debt and equity. Southern Company finances its capital needs on a portfolio basis and expects to issue approximately $8.0 billion in debt prior to closing the Merger and approximately $1.2 billion in equity during 2016. This capital is expected to provide funding for the Merger, Southern Power growth opportunities, and other Southern Company system capital projects. Southern Company expects to issue the debt to fund the Merger Consideration in several tranches including long-dated maturities. The amount of debt issued at each maturity will depend on prevailing market conditions at the time of the offering and other factors. In addition, Southern Company entered into the $8.1 billion Bridge Agreement on September 30, 2015 to provide financing for the Merger in the event long-term financing is not available.

The Bridge Agreement provides for total loan commitments in an aggregate amount of $8.1 billion to fund the payment of the cash consideration payable under the Merger Agreement and other cash payments required in connection with the consummation of the Merger, the Bridge Agreement and the borrowings thereunder, the other financing transactions related to the Merger, and the payment of fees and expenses incurred in connection with the foregoing. If funded, the loan under the Bridge Agreement will mature and be payable in full on the date that is 364 days after the funding of the commitments under the Bridge Agreement (Closing Date).

In connection with the Bridge Agreement, Southern Company will pay a ticking fee for the benefit of the lenders thereto, accruing from November 21, 2015, in an amount equal to 0.125% per annum of the aggregate commitments under the Bridge Agreement, which fee will accrue through the earlier of (i) the date of termination of the commitments and (ii) the Closing Date. Additionally, under the terms of the Bridge Agreement, Southern Company is required to pay certain customary fees to the lenders as set forth in related letters. As of December 31, 2015, Southern Company had no outstanding loans under the Bridge Agreement.

Southern Company, the traditional operating companies, and Southern Power make short-term borrowings primarily through commercial paper programs that have the liquidity support of the committed bank credit arrangements described above, excluding the Bridge Agreement. Southern Company, the traditional operating companies, and Southern Power may also borrow through various other arrangements with banks. 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, 2015:					
Commercial paper	**$ 740**	**0.7%**	**$ 842**	**0.4%**	**$ 1,563**
Short-term bank debt	**500**	**1.4%**	**444**	**1.1%**	**795**
Total	**$ 1,240**	**0.9%**	**$ 1,286**	**0.5%**	
December 31, 2014:					
Commercial paper	$ 803	0.3%	$ 754	0.2%	$ 1,582
Short-term bank debt	—	—%	98	0.8%	400
Total	$ 803	0.3%	$ 852	0.3%	
December 31, 2013:					
Commercial paper	$ 1,082	0.2%	$ 993	0.3%	$ 1,616
Short-term bank debt	400	0.9%	107	0.9%	400
Total	$ 1,482	0.4%	$ 1,100	0.3%	

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

In addition to the short-term borrowings in the table above, the Project Credit Facilities had total amounts outstanding as of December 31, 2015 of $137 million at a weighted average interest rate of 2.0%. For the year ended December 31, 2015, the Project Credit Facilities had a maximum amount outstanding of $137 million, and an average amount outstanding of $13 million at a weighted average interest rate of 2.0%.

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

Financing Activities

During 2015, Southern Company issued approximately 6.6 million shares of common stock primarily through the employee equity compensation plan and received proceeds of approximately $256 million. During the first nine months of 2015, all sales under the Southern Investment Plan and the Employee Savings Plan were funded with shares acquired on the open market by independent plan administrators. In October 2015, Southern Company began issuing shares of common stock through the Southern Investment Plan and the Employee Savings Plan. The Company may satisfy its obligations with respect to the plans in several ways, including through using newly issued shares or treasury shares or acquiring shares on the open market through the independent plan administrators.

On March 2, 2015, Southern Company announced a program to repurchase up to 20 million shares of Southern Company common stock to offset all or a portion of the incremental shares issued under its employee and director stock plans, including through stock option exercises, until December 31, 2017. Under this program, approximately 2.6 million shares were repurchased in 2015 at a total cost of approximately $115 million. No further repurchases under the program are anticipated.

The following table outlines the long-term debt financing activities for Southern Company and its subsidiaries for the year ended December 31, 2015:

Company	Senior Note Issuances	Senior Note Maturities and Redemptions	Revenue Bond Issuances and Reofferings of Purchased Bonds[(a)]	Revenue Bond Maturities, Redemptions, and Repurchases	Other Long-Term Debt Issuances	Other Long-Term Debt Redemptions and Maturities[(b)]
		(in millions)		*(in millions)*		
Southern Company	$ 600	$ 400	$ —	$ —	$ 1,400	$ —
Alabama Power	975	650	80	134	—	—
Georgia Power	500	1,175	409	267	1,000	6
Gulf Power	—	60	13	13	—	—
Mississippi Power	—	—	—	—	275	353
Southern Power	1,650	525	—	—	402	4
Other	—	—	—	—	—	17
Elimination[(c)]	—	—	—	—	(275)	—
Total	$ 3,725	$ 2,810	$ 502	$ 414	$ 2,802	$ 380

(a) Includes a reoffering by Alabama Power of $80.0 million aggregate principal amount of revenue bonds purchased and held since April 2015; reofferings by Georgia Power of $135.2 million, $104.6 million, and $65.0 million aggregate principal amount of revenue bonds purchased and held since 2010, 2013, and April 2015, respectively; and a reoffering by Gulf Power of $13.0 million aggregate principal amount of revenue bonds purchased and held in July 2015. Also includes repurchases and reofferings by Georgia Power of $94.6 million and $10.0 million aggregate principal amount of revenue bonds in August 2015 in connection with optional tenders.
(b) Includes reductions in capital lease obligations resulting from cash payments under capital leases.
(c) Intercompany loan from Southern Company to Mississippi Power eliminated in Southern Company's Consolidated Financial Statements.

In June 2015, Southern Company issued $600 million aggregate principal amount of Series 2015A 2.750% Senior Notes due June 15, 2020. The proceeds were used to pay a portion of Southern Company's outstanding short-term indebtedness and for other general corporate purposes.

In September 2015, Southern Company entered into a $400 million aggregate principal amount 18-month floating rate bank loan bearing interest based on one-month LIBOR. The proceeds were used for working capital and other general corporate purposes.

Also in September 2015, Southern Company repaid at maturity $400 million aggregate principal amount of its Series 2010A 2.375% Senior Notes due September 15, 2015.

In October 2015, Southern Company issued $1.0 billion aggregate principal amount of Series 2015A 6.25% Junior Subordinated Notes due October 15, 2075. The proceeds were used to pay a portion of Southern Company's outstanding short-term indebtedness and for other general corporate purposes.

In November and December 2015, Southern Company entered into forward-starting interest rate swaps to hedge exposure to interest rate changes related to anticipated debt issuances. The notional amount of the swaps totaled $2 billion. Subsequent to December 31, 2015, Southern Company entered into an additional $700 million notional amount of forward-starting interest rate swaps.

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

A portion of the proceeds of Alabama Power's senior note issuances were used in May 2015 to redeem 6.48 million shares ($162 million aggregate stated capital) of Alabama Power's 5.20% Class A Preferred Stock at a redemption price of $25 per share plus accrued and unpaid dividends to the redemption date, 4.0 million shares ($100 million aggregate stated capital) of Alabama Power's 5.30% Class A Preferred Stock at a redemption price of $25 per share plus accrued and unpaid dividends to the redemption date, and 6.0 million shares ($150 million aggregate stated capital) of Alabama Power's 5.625% Series Preference Stock at a redemption price of $25 per share plus accrued and unpaid dividends to the redemption date.

Georgia Power's "Other Long-Term Debt Issuances" reflected in the table above include borrowings in June and December 2015 under the FFB Credit Facility in an aggregate principal amount of $600 million and $400 million, respectively. The interest rate applicable to the $600 million principal amount is 3.283% and the interest rate applicable to the $400 million principal amount is 3.072%, both for an interest period that extends to the final maturity date of February 20, 2044. The proceeds were used to reimburse Georgia Power for Eligible Project Costs relating to the construction of Plant Vogtle Units 3 and 4.

In March 2015, Georgia Power entered into a $250 million aggregate principal amount three-month floating rate bank loan bearing interest based on one-month LIBOR. The loan was repaid at maturity.

In April 2015, Mississippi Power entered into two short-term floating rate bank loans with a maturity date of April 1, 2016, in an aggregate principal amount of $475 million, bearing interest based on one-month LIBOR. A portion of the proceeds of these loans were used for the repayment of term loans in an aggregate principal amount of $275 million. Mississippi Power also amended three outstanding floating rate bank loans for an aggregate principal amount of $425 million which, among other things, extended the maturity dates from various dates in 2015 to April 1, 2016.

In addition to the amounts reflected in the table above, Mississippi Power previously received a total of $275 million of deposits from SMEPA that were required to be returned to SMEPA with interest in connection with the termination of the APA. On June 3, 2015, Southern Company, pursuant to its guarantee obligation, returned approximately $301 million to SMEPA. Subsequently, Mississippi Power issued a floating rate promissory note to Southern Company in an aggregate principal amount of approximately $301 million bearing interest based on one-month LIBOR, which matures on December 1, 2017. See Note 3 to the financial statements under "Integrated Coal Gasification Combined Cycle – Termination of Proposed Sale of Undivided Interest to SMEPA" for additional information.

In June 2015, Gulf Power entered into a $40 million aggregate principal amount three-month floating rate bank loan bearing interest based on one-month LIBOR. The loan was repaid at maturity.

In October 2015, Gulf Power entered into forward-starting interest rate swaps to hedge exposure to interest rate changes related to an anticipated debt issuance. The notional amount of the swaps totaled $80 million.

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

Subsequent to December 31, 2015, Southern Power borrowed $182 million pursuant to the Project Credit Facilities at a weighted average interest rate of 2.0%.

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

Southern Company and its subsidiaries 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 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 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, 2015 were as follows:

Credit Ratings	Maximum Potential Collateral Requirements
	(in millions)
At BBB and/or Baa2	$ 12
At BBB- and/or Baa3	$ 508
Below BBB- and/or Baa3	$ 2,432

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 June 5, 2015, Fitch Ratings, Inc. (Fitch) downgraded the long-term issuer default rating of Mississippi Power to BBB+ from A-. Fitch maintained the negative ratings outlook for Mississippi Power and revised the ratings outlook for Southern Company from stable to negative.

On August 14, 2015, Moody's downgraded the senior unsecured debt rating of Mississippi Power to Baa2 from Baa1. Moody's maintained the negative ratings outlook for Mississippi Power.

On August 17, 2015, S&P downgraded the consolidated long-term issuer rating of Southern Company (including Alabama Power, Georgia Power, and Gulf Power) to A- from A. Also on August 17, 2015, S&P downgraded the issuer rating of Mississippi Power to BBB+ from A. S&P revised its credit rating outlook for Southern Company and the traditional operating companies to stable from negative. Separately, on August 24, 2015, S&P revised its credit rating outlook for Southern Company, the traditional operating companies, and Southern Power Company from stable to negative following the announcement of the Merger.

Also following the announcement of the Merger, on August 24, 2015, Moody's affirmed the rating of Southern Company and revised its credit rating outlook from stable to negative. On the same date, Fitch placed the ratings of Southern Company on ratings watch negative.

On November 5, 2015, Moody's downgraded the senior unsecured debt rating of Mississippi Power to Baa3 from Baa2. Moody's maintained the negative ratings outlook for Mississippi Power.

Market Price Risk

The Southern Company system is exposed to market risks, primarily commodity price risk and interest rate risk. The Southern Company system may also occasionally have limited exposure to foreign currency exchange rates. To manage the volatility attributable to these exposures, the applicable company nets the exposures, where possible, to take advantage of natural offsets and enters into various derivative transactions for the remaining exposures pursuant to the applicable company's policies in areas such as counterparty exposure and risk management practices. The Southern Company system's policy is that derivatives are to be used primarily for hedging purposes and mandates strict adherence to all applicable risk management policies. Derivative positions are monitored using techniques including, but not limited to, market valuation, value at risk, stress testing, and sensitivity analysis.

To mitigate future exposure to a change in interest rates, Southern Company and certain of its subsidiaries enter into derivatives that have been designated as hedges. Derivatives, that have been designated as hedges, outstanding at December 31, 2015 have a notional amount of $4.2 billion, of which $2.3 billion are to mitigate interest rate volatility related to projected debt financings in 2016. The remaining $1.9 billion are related to existing fixed and floating rate obligations. The weighted average interest rate on $5.2 billion of long-term variable interest rate exposure at January 1, 2016 was 1.19%. 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 $52 million at January 1, 2016. See Note 1 to the financial statements under "Financial Instruments" and Note 11 to the financial statements for additional information.

Due to cost-based rate regulation and other various cost recovery mechanisms, the traditional operating companies continue to have limited exposure to market volatility in interest rates, foreign currency, 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 operating companies and Southern Power may enter into physical fixed-price or heat rate 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 operating companies continue to manage fuel-hedging programs implemented per the guidelines of their respective state PSCs. Southern Company had no material change in market risk exposure for the year ended December 31, 2015 when compared to the year ended December 31, 2014.

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

	2015 Changes	2014 Changes
	Fair Value	
	(in millions)	
Contracts outstanding at the beginning of the period, assets (liabilities), net	**$ (188)**	$ (32)
Contracts realized or settled:		
Swaps realized or settled	**121**	(9)
Options realized or settled	**21**	6
Current period changes(*):		
Swaps	**(152)**	(131)
Options	**(15)**	(22)
Contracts outstanding at the end of the period, assets (liabilities), net	**$ (213)**	$ (188)

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

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

	2015	2014
	mmBtu Volume	
	(in millions)	
Commodity – Natural gas swaps	**168**	200
Commodity – Natural gas options	**56**	44
Total hedge volume	**224**	244

The weighted average swap contract cost above market prices was approximately $1.14 per mmBtu as of December 31, 2015 and $0.84 per mmBtu as of December 31, 2014. The change in option fair value is primarily attributable to the volatility of the market and the underlying change in the natural gas price. The majority of the natural gas hedge gains and losses are recovered through the traditional operating companies' fuel cost recovery clauses.

At December 31, 2015 and 2014, substantially all of the Southern Company system's energy-related derivative contracts were designated as regulatory hedges and were related to the applicable company's fuel-hedging program. Therefore, gains and losses are initially recorded as regulatory liabilities and assets, respectively, and then are included in fuel expense as they are recovered through the energy cost recovery clause. Certain other gains and losses on energy-related derivatives, designated as cash flow hedges, are initially deferred in OCI before being recognized in income in the same period as the hedged transaction. Gains and losses on energy-related derivative contracts that are not designated or fail to qualify as hedges are recognized in the statements of income as incurred and were not material for any year presented.

Southern Company uses over-the-counter contracts that are not exchange traded but are fair valued using prices which are market observable, and thus fall into Level 2. See Note 10 to the financial statements for further discussion of fair value measurements. The maturities of the energy-related derivative contracts, which are all Level 2 of the fair value hierarchy, at December 31, 2015 were as follows:

	Fair Value Measurements December 31, 2015			
		Maturity		
	Total Fair Value	Year 1	Years 2&3	Years 4&5
	(in millions)			
Level 1	$ —	$ —	$ —	$ —
Level 2	213	126	82	5
Level 3	—	—	—	—
Fair value of contracts outstanding at end of period	$ 213	$ 126	$ 82	$ 5

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

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

Capital Requirements and Contractual Obligations

The Southern Company system's construction program is currently estimated to total $7.3 billion for 2016, $5.2 billion for 2017, and $5.5 billion for 2018. These amounts include expenditures of approximately $0.6 billion related to the construction and start-up of the Kemper IGCC in 2016; $0.6 billion, $0.7 billion, and $0.4 billion to continue construction on Plant Vogtle Units 3 and 4 in 2016, 2017, and 2018, respectively; and $2.2 billion, $0.9 billion, and $1.4 billion for acquisitions and/or construction of new Southern Power generating facilities in 2016, 2017, and 2018, respectively. These amounts also include capital expenditures related to contractual purchase commitments for nuclear fuel and capital expenditures covered under long-term service agreements. Estimated capital expenditures to comply with environmental statutes and regulations included in these amounts are $0.7 billion, $0.5 billion, and $0.6 billion for 2016, 2017, and 2018, respectively. These estimated expenditures do not include any potential compliance costs that may arise from the EPA's final rules and guidelines or subsequently approved state plans that would limit CO_2 emissions from new, existing, and modified or reconstructed fossil-fuel-fired electric generating units. See FUTURE EARNINGS POTENTIAL – "Environmental Matters – Environmental Statutes and Regulations" and "– Global Climate Issues" herein for additional information.

The Southern Company system also anticipates costs associated with closure in place or by other methods, and ground water monitoring of ash ponds in accordance with the CCR Rule, which are not reflected in the capital expenditures above as these costs are associated with the Company's ARO liabilities. These costs, which could change as the Southern Company system continues to refine its assumptions underlying the cost estimates and evaluate the method and timing of compliance, are estimated to be approximately $0.2 billion, $0.2 billion, and $0.3 billion for 2016, 2017, and 2018, respectively. See Note 1 to the financial statements under "Asset Retirement Obligations and Other Costs of Removal" for additional information.

The construction programs are subject to periodic review and revision, and actual construction costs may vary from these estimates because of numerous factors. These factors include: changes in business conditions; changes in load projections; changes in environmental statutes and regulations; the outcome of any legal challenges to the environmental rules; changes in generating plants, including unit retirements and replacements and adding or changing fuel sources at existing units, to meet regulatory requirements; changes in FERC rules and regulations;

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. Additionally, planned expenditures for plant acquisitions may vary due to market opportunities and Southern Power's ability to execute its growth strategy. See Note 12 to the financial statements under "Southern Power" for additional information regarding Southern Power's plant acquisitions. See Note 3 to the financial statements under "Retail Regulatory Matters – Georgia Power – Nuclear Construction" and "Integrated Coal Gasification Combined Cycle" for information regarding additional factors that may impact construction expenditures.

In addition, the construction program includes the development and construction of new generating facilities with designs that have not been finalized or previously constructed, including first-of-a-kind technology, which may result in revised estimates during construction. The ability to control costs and avoid cost overruns during the development and construction of new facilities is subject to a number of factors, including, but not limited to, changes in labor costs and productivity, adverse weather conditions, shortages and inconsistent quality of equipment, materials, and labor, contractor or supplier delay, non-performance under construction, operating, or other agreements, operational readiness, including specialized operator training and required site safety programs, unforeseen engineering or design problems, start-up activities (including major equipment failure and system integration), and/or operational performance (including additional costs to satisfy any operational parameters ultimately adopted by any PSC).

In addition to the Merger Consideration to be paid by Southern Company at the Effective Time, in connection with the Merger, Southern Company will also assume AGL Resources' outstanding indebtedness (approximately $4.8 billion at December 31, 2015). See OVERVIEW herein for additional information regarding the Merger, including the Merger Consideration, as well as Note 12 to the financial statements.

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

In addition, as discussed in Note 2 to the financial statements, Southern Company provides postretirement benefits to substantially all employees and funds trusts to the extent required by the traditional operating companies' respective regulatory commissions.

Other funding requirements related to obligations associated with scheduled maturities of long-term debt, as well as the related interest, derivative obligations, preferred and preference stock dividends, leases, unrecognized tax benefits, other purchase commitments, and trusts are detailed in the contractual obligations table that follows. See Notes 1, 2, 5, 6, 7, and 11 to the financial statements for additional information.

Contractual Obligations

	2016	2017-2018	2019-2020	After 2020	Total
			(in millions)		
Long-term debt[a] —					
Principal	$ 2,642	$ 4,128	$ 2,572	$ 18,090	$ 27,432
Interest	997	1,794	1,576	14,948	19,315
Preferred and preference stock dividends[b]	45	91	91	—	227
Financial derivative obligations[c]	156	83	5	—	244
Operating leases[d]	121	184	114	706	1,125
Capital leases[d]	32	28	23	63	146
Unrecognized tax benefits[e]	9	424	—	—	433
Purchase commitments —					
Capital[f]	6,906	9,780	—	—	16,686
Fuel[g]	3,201	4,473	2,566	7,378	17,618
Purchased power[h]	380	803	840	3,762	5,785
Other[i]	281	637	482	1,661	3,061
Trusts —					
Nuclear decommissioning[j]	5	11	11	104	131
Pension and other postretirement benefit plans[k]	117	232	—	—	349
Total	$ 14,892	$ 22,668	$ 8,280	$ 46,712	$ 92,552

(a) All amounts are reflected based on final maturity dates except for amounts related to FFB borrowings. As it relates to the FFB borrowings, the final maturity date is February 20, 2044; however, principal amortization is reflected beginning in 2020. See Note 6 to the financial statements under "DOE Loan Guarantee Borrowings" for additional information. Southern Company and its subsidiaries plan to continue, when economically feasible, to retire higher-cost securities and replace these obligations with lower-cost capital if market conditions permit. Variable rate interest obligations are estimated based on rates as of January 1, 2016, as reflected in the statements of capitalization. Fixed rates include, where applicable, the effects of interest rate derivatives employed to manage interest rate risk. Long-term debt excludes capital lease amounts (shown separately).

(b) Represents preferred and preference stock of subsidiaries. Preferred and preference stock do not mature; therefore, amounts are provided for the next five years only.

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

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

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

(f) The Southern Company system provides estimated capital expenditures for a three-year period, including capital expenditures associated with environmental regulations. These amounts exclude contractual purchase commitments for nuclear fuel and capital expenditures covered under long-term service agreements which are reflected in "Fuel" and "Other," respectively. At December 31, 2015, significant purchase commitments were outstanding in connection with the construction program. See FUTURE EARNINGS POTENTIAL – "Environmental Matters – Environmental Statutes and Regulations" herein for additional information.

(g) Primarily includes commitments to purchase coal, nuclear fuel, and natural gas, as well as the related transportation and storage. In most cases, these contracts contain provisions for price escalation, minimum purchase levels, and other financial commitments. Natural gas purchase commitments are based on various indices at the time of delivery. Amounts reflected for natural gas purchase commitments have been estimated based on the New York Mercantile Exchange future prices at December 31, 2015.

(h) Estimated minimum long-term obligations for various PPA purchases from gas-fired, biomass, and wind-powered facilities. Includes a total of $304 million of biomass PPAs that is contingent upon the counterparties meeting specified contract dates for commercial operation and may change as a result of regulatory action. See FUTURE EARNINGS POTENTIAL – "Retail Regulatory Matters – Georgia Power – Renewables Development" herein for additional information.

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

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

(K) 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 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 corporate assets of Southern Company's subsidiaries. See Note 2 to the financial statements for additional information related to the pension and other postretirement benefit plans, including estimated benefit payments. Certain benefit payments will be made through the related benefit plans. Other benefit payments will be made from corporate assets of Southern Company's subsidiaries.

Cautionary Statement Regarding Forward-Looking Statements

Southern Company's 2015 Annual Report contains forward-looking statements. Forward-looking statements include, among other things, statements concerning retail rates, the potential financing of the Merger, the expected timing of the completion of the Merger, the strategic goals for the wholesale business, economic recovery, fuel and environmental cost recovery and other rate actions, current and proposed environmental regulations and related compliance plans and estimated expenditures, pending or potential litigation matters, access to sources of capital, projections for the qualified pension plan, postretirement benefit plans, and nuclear decommissioning trust fund contributions, financing activities, completion dates of acquisitions, construction projects, and changing fuel sources, filings with state and federal regulatory authorities, impact of the PATH Act, federal income tax benefits, estimated sales and purchases under power sale and purchase agreements, and estimated construction and other plans and expenditures. In some cases, forward-looking statements can be identified by terminology such as "may," "will," "could," "should," "expects," "plans," "anticipates," "believes," "estimates," "projects," "predicts," "potential," or "continue" or the negative of these terms or other similar terminology. There are various factors that could cause actual results to differ materially from those suggested by the forward-looking statements; accordingly, there can be no assurance that such indicated results will be realized. These factors include:

- the impact of recent and future federal and state regulatory changes, including legislative and regulatory initiatives regarding deregulation and restructuring of the electric utility industry, environmental laws regulating emissions, discharges, and disposal to air, water, and land, and also changes in tax and other laws and regulations to which Southern Company and its subsidiaries are subject, as well as changes in application of existing laws and regulations;
- current and future litigation, regulatory investigations, proceedings, or inquiries, including, without limitation, IRS and state tax audits;
- the effects, extent, and timing of the entry of additional competition in the markets in which Southern Company's subsidiaries operate;
- variations in demand for electricity, including those relating to weather, the general economy and recovery from the last recession, population and business growth (and declines), the effects of energy conservation and efficiency measures, including from the development and deployment of alternative energy sources such as self-generation and distributed generation technologies, and any potential economic impacts resulting from federal fiscal decisions;

- available sources and costs of fuels;
- effects of inflation;
- the ability to control costs and avoid cost overruns during the development and construction of facilities, which include the development and construction of generating facilities with designs that have not been finalized or previously constructed, including changes in labor costs and productivity, adverse weather conditions, shortages and inconsistent quality of equipment, materials, and labor, contractor or supplier delay, non-performance under construction, operating, or other agreements, operational readiness, including specialized operator training and required site safety programs, unforeseen engineering or design problems, start-up activities (including major equipment failure and system integration), and/or operational performance (including additional costs to satisfy any operational parameters ultimately adopted by any PSC);
- the ability to construct facilities in accordance with the requirements of permits and licenses, to satisfy any environmental performance standards and the requirements of tax credits and other incentives, and to integrate facilities into the Southern Company system upon completion of construction;
- investment performance of Southern Company's employee and retiree benefit plans and the Southern Company system's nuclear decommissioning trust funds;
- advances in technology;
- state and federal rate regulations and the impact of pending and future rate cases and negotiations, including rate actions relating to fuel and other cost recovery mechanisms;
- legal proceedings and regulatory approvals and actions related to Plant Vogtle Units 3 and 4, including Georgia PSC approvals and NRC actions and related legal proceedings involving the commercial parties;
- actions related to cost recovery for the Kemper IGCC, including the ultimate impact of the 2015 decision of the Mississippi Supreme Court, the Mississippi PSC's December 2015 rate order, and related legal or regulatory proceedings, Mississippi PSC review of the prudence of Kemper IGCC costs and approval of further permanent rate recovery plans, actions relating to proposed securitization, satisfaction of requirements to utilize grants, and the ultimate impact of the termination of the proposed sale of an interest in the Kemper IGCC to SMEPA;
- the ability to successfully operate the electric utilities' generating, transmission, and distribution facilities and the successful performance of necessary corporate functions;
- the inherent risks involved in operating and constructing nuclear generating facilities, including environmental, health, regulatory, natural disaster, terrorism, and financial risks;
- the performance of projects undertaken by the non-utility businesses and the success of efforts to invest in and develop new opportunities;
- internal restructuring or other restructuring options that may be pursued;
- potential business strategies, including acquisitions or dispositions of assets or businesses, which cannot be assured to be completed or beneficial to Southern Company or its subsidiaries;
- the expected timing, likelihood, and benefits of completion of the Merger, including the failure to receive, on a timely basis or otherwise, the required approvals by government or regulatory agencies (including the terms of such approvals), the possibility that long-term financing for the Merger may not be put in place prior to the closing, the risk that a condition to closing of the Merger or funding of the Bridge Agreement may not be satisfied, the possibility that the anticipated benefits from the Merger cannot be fully realized or may take longer to realize than expected, the possibility that costs related to the integration of Southern Company and AGL Resources will be greater than expected, the credit ratings of the combined company or its subsidiaries may be different from what the parties expect, the ability to retain and hire key personnel and maintain relationships with customers, suppliers, or other business partners, the diversion of management time on Merger-related issues, and the impact of legislative, regulatory, and competitive changes;
- the ability of counterparties of Southern Company and its subsidiaries to make payments as and when due and to perform as required;
- the ability to obtain new short- and long-term contracts with wholesale customers;
- the direct or indirect effect on the Southern Company system's business resulting from cyber intrusion or terrorist incidents and the threat of terrorist incidents;
- interest rate fluctuations and financial market conditions and the results of financing efforts;
- changes in Southern Company's and any of its subsidiaries' credit ratings, including impacts on interest rates, access to capital markets, and collateral requirements;
- the impacts of any sovereign financial issues, including impacts on interest rates, access to capital markets, impacts on currency exchange rates, counterparty performance, and the economy in general, as well as potential impacts on the benefits of the DOE loan guarantees;
- the ability of Southern Company's subsidiaries to obtain additional generating capacity (or sell excess generating capacity) at competitive prices;
- catastrophic events such as fires, earthquakes, explosions, floods, hurricanes and other storms, droughts, pandemic health events such as influenzas, or other similar occurrences;
- the direct or indirect effects on the Southern Company system's business resulting from incidents affecting the U.S. electric grid or operation of generating resources;
- the effect of accounting pronouncements issued periodically by standard-setting bodies; and
- other factors discussed elsewhere herein and in other reports (including the Form 10-K) filed by Southern Company from time to time with the SEC.

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

CONSOLIDATED STATEMENTS OF INCOME

For the Years Ended December 31, 2015, 2014, and 2013

	2015	2014	2013
		(in millions)	
Operating Revenues:			
Retail revenues	**$ 14,987**	$ 15,550	$ 14,541
Wholesale revenues	**1,798**	2,184	1,855
Other electric revenues	**657**	672	639
Other revenues	**47**	61	52
Total operating revenues	**17,489**	18,467	17,087
Operating Expenses:			
Fuel	**4,750**	6,005	5,510
Purchased power	**645**	672	461
Other operations and maintenance	**4,416**	4,354	3,846
Depreciation and amortization	**2,034**	1,945	1,901
Taxes other than income taxes	**997**	981	934
Estimated loss on Kemper IGCC	**365**	868	1,180
Total operating expenses	**13,207**	14,825	13,832
Operating Income	**4,282**	3,642	3,255
Other Income and (Expense):			
Allowance for equity funds used during construction	**226**	245	190
Interest income	**23**	19	19
Interest expense, net of amounts capitalized	**(840)**	(835)	(824)
Other income (expense), net	**(62)**	(63)	(81)
Total other income and (expense)	**(653)**	(634)	(696)
Earnings Before Income Taxes	**3,629**	3,008	2,559
Income taxes	**1,194**	977	849
Consolidated Net Income	**2,435**	2,031	1,710
Less:			
Dividends on preferred and preference stock of subsidiaries	**54**	68	66
Net income attributable to noncontrolling interests	**14**	—	—
Consolidated Net Income Attributable to Southern Company	**$ 2,367**	$ 1,963	$ 1,644
Common Stock Data:			
Earnings per share (EPS) —			
Basic EPS	**$ 2.60**	$ 2.19	$ 1.88
Diluted EPS	**2.59**	2.18	1.87
Average number of shares of common stock outstanding — (in millions)			
Basic	**910**	897	877
Diluted	**914**	901	881

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

CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME

For the Years Ended December 31, 2015, 2014, and 2013

	2015	2014	2013
		(in millions)	
Consolidated Net Income	**$ 2,435**	$ 2,031	$ 1,710
Other comprehensive income:			
Qualifying hedges:			
Changes in fair value, net of tax of $(8), $(6), and $-, respectively	**(13)**	(10)	—
Reclassification adjustment for amounts included in net income, net of tax of $4, $3, and $5, respectively	**6**	5	9
Marketable securities:			
Change in fair value, net of tax of $-, $-, and $(2), respectively	**—**	—	(3)
Pension and other postretirement benefit plans:			
Benefit plan net gain (loss), net of tax of $(1), $(32), and $22, respectively	**(2)**	(51)	36
Reclassification adjustment for amounts included in net income, net of tax of $4, $2, and $4, respectively	**7**	3	6
Total other comprehensive income (loss)	**(2)**	(53)	48
Less:			
Dividends on preferred and preference stock of subsidiaries	**54**	68	66
Comprehensive income attributable to noncontrolling interests	**14**	—	—
Consolidated Comprehensive Income Attributable to Southern Company	**$ 2,365**	$ 1,910	$ 1,692

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

CONSOLIDATED STATEMENTS OF CASH FLOWS

For the Years Ended December 31, 2015, 2014, and 2013

	2015	2014	2013
		(in millions)	
Operating Activities:			
Consolidated net income	**$ 2,435**	$ 2,031	$ 1,710
Adjustments to reconcile consolidated net income to net cash provided from operating activities —			
Depreciation and amortization, total	**2,395**	2,293	2,298
Deferred income taxes	**1,404**	709	496
Investment tax credits	**(48)**	35	302
Allowance for equity funds used during construction	**(226)**	(245)	(190)
Pension, postretirement, and other employee benefits	**76**	(515)	131
Stock based compensation expense	**99**	63	59
Estimated loss on Kemper IGCC	**365**	868	1,180
Income taxes receivable, non-current	**(413)**	—	—
Other, net	**(39)**	(39)	(41)
Changes in certain current assets and liabilities —			
-Receivables	**243**	(352)	(153)
-Fossil fuel stock	**61**	408	481
-Materials and supplies	**(44)**	(67)	36
-Other current assets	**(108)**	(57)	(11)
-Accounts payable	**(353)**	267	72
-Accrued taxes	**352**	(105)	(85)
-Accrued compensation	**(41)**	255	(138)
-Retail fuel cost over recovery — short-term	**289**	(23)	(66)
-Mirror CWIP	**(271)**	180	—
-Other current liabilities	**98**	109	16
Net cash provided from operating activities	**6,274**	5,815	6,097
Investing Activities:			
Plant acquisitions	**(1,719)**	(731)	(132)
Property additions	**(5,674)**	(5,246)	(5,331)
Investment in restricted cash	**(160)**	(11)	(149)
Distribution of restricted cash	**154**	57	96
Nuclear decommissioning trust fund purchases	**(1,424)**	(916)	(986)
Nuclear decommissioning trust fund sales	**1,418**	914	984
Cost of removal, net of salvage	**(167)**	(170)	(131)
Change in construction payables, net	**402**	(107)	(126)
Prepaid long-term service agreement	**(197)**	(181)	(91)
Other investing activities	**87**	(17)	124
Net cash used for investing activities	**(7,280)**	(6,408)	(5,742)
Financing Activities:			
Increase (decrease) in notes payable, net	**73**	(676)	662
Proceeds —			
Long-term debt issuances	**7,029**	3,169	2,938
Interest-bearing refundable deposit	**—**	125	—
Common stock issuances	**256**	806	695
Short-term borrowings	**755**	—	—

	2015	2014	2013
		(in millions)	
Redemptions and repurchases —			
Long-term debt	**(3,604)**	(816)	(2,830)
Common stock repurchased	**(115)**	(5)	(20)
Interest-bearing refundable deposits	**(275)**	—	—
Preferred and preference stock	**(412)**	—	—
Short-term borrowings	**(255)**	—	—
Capital contributions from noncontrolling interests	**341**	8	17
Payment of common stock dividends	**(1,959)**	(1,866)	(1,762)
Payment of dividends on preferred and preference stock of subsidiaries	**(59)**	(68)	(66)
Other financing activities	**(75)**	(33)	42
Net cash provided from (used for) financing activities	**1,700**	644	(324)
Net Change in Cash and Cash Equivalents	**694**	51	31
Cash and Cash Equivalents at Beginning of Year	**710**	659	628
Cash and Cash Equivalents at End of Year	**$ 1,404**	$ 710	$ 659

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

CONSOLIDATED BALANCE SHEETS

At December 31, 2015 and 2014

Assets	2015	2014
	(in millions)	
Current Assets:		
Cash and cash equivalents	**$ 1,404**	$ 710
Receivables —		
Customer accounts receivable	**1,058**	1,090
Unbilled revenues	**397**	432
Under recovered regulatory clause revenues	**63**	136
Other accounts and notes receivable	**398**	307
Accumulated provision for uncollectible accounts	**(13)**	(18)
Income taxes receivable, current	**144**	—
Fossil fuel stock, at average cost	**868**	930
Materials and supplies, at average cost	**1,061**	1,039
Vacation pay	**178**	177
Prepaid expenses	**495**	665
Other regulatory assets, current	**402**	346
Other current assets	**71**	50
Total current assets	**6,526**	5,864
Property, Plant, and Equipment:		
In service	**75,118**	70,013
Less accumulated depreciation	**24,253**	24,059
Plant in service, net of depreciation	**50,865**	45,954
Other utility plant, net	**233**	211
Nuclear fuel, at amortized cost	**934**	911
Construction work in progress	**9,082**	7,792
Total property, plant, and equipment	**61,114**	54,868
Other Property and Investments:		
Nuclear decommissioning trusts, at fair value	**1,512**	1,546
Leveraged leases	**755**	743
Miscellaneous property and investments	**485**	203
Total other property and investments	**2,752**	2,492
Deferred Charges and Other Assets:		
Deferred charges related to income taxes	**1,560**	1,510
Unamortized loss on reacquired debt	**227**	243
Other regulatory assets, deferred	**4,989**	4,334
Income taxes receivable, non-current	**413**	—
Other deferred charges and assets	**737**	922
Total deferred charges and other assets	**7,926**	7,009
Total Assets	**$ 78,318**	$ 70,233

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

Liabilities and Stockholders' Equity	2015	2014
	(in millions)	
Current Liabilities:		
Securities due within one year	$ **2,674**	$ 3,329
Interest-bearing refundable deposits	**—**	275
Notes payable	**1,376**	803
Accounts payable	**1,905**	1,593
Customer deposits	**404**	390
Accrued taxes —		
Accrued income taxes	**19**	149
Other accrued taxes	**484**	487
Accrued interest	**249**	295
Accrued vacation pay	**228**	223
Accrued compensation	**549**	576
Asset retirement obligations, current	**217**	32
Liabilities from risk management activities	**156**	138
Other regulatory liabilities, current	**278**	26
Mirror CWIP	**—**	271
Other current liabilities	**590**	374
Total current liabilities	**9,129**	8,961
Long-Term Debt (See accompanying statements)	**24,688**	20,644
Deferred Credits and Other Liabilities:		
Accumulated deferred income taxes	**12,322**	11,082
Deferred credits related to income taxes	**187**	192
Accumulated deferred investment tax credits	**1,219**	1,208
Employee benefit obligations	**2,582**	2,432
Asset retirement obligations, deferred	**3,542**	2,168
Unrecognized tax benefits	**370**	4
Other cost of removal obligations	**1,162**	1,215
Other regulatory liabilities, deferred	**254**	398
Other deferred credits and liabilities	**720**	589
Total deferred credits and other liabilities	**22,358**	19,288
Total Liabilities	**56,175**	48,893
Redeemable Preferred Stock of Subsidiaries (See accompanying statements)	**118**	375
Redeemable Noncontrolling Interests (See accompanying statements)	**43**	39
Total Stockholders' Equity (See accompanying statements)	**21,982**	20,926
Total Liabilities and Stockholders' Equity	$ **78,318**	$ 70,233
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, 2015 and 2014

		2015	2014	**2015**	2014
		(in millions)		*(percent of total)*	
Long-Term Debt:					
Long-term debt payable to affiliated trusts —					
Variable rate (3.43% at 1/1/16) due 2042		**$ 206**	$ 206		
Long-term senior notes and debt —					
Maturity	Interest Rates				
2015	0.55% to 5.25%	**—**	2,375		
2016	1.95% to 5.30%	**1,360**	1,360		
2017	1.30% to 5.90%	**1,995**	1,495		
2018	1.50% to 5.40%	**1,697**	850		
2019	2.15% to 5.55%	**1,176**	1,175		
2020	2.38% to 4.75%	**1,327**	425		
2021 through 2051	1.63% to 6.38%	**11,185**	10,150		
Variable rates (0.77% to 1.17% at 1/1/15) due 2015		**—**	775		
Variable rates (0.76% to 3.50% at 1/1/16) due 2016		**1,278**	450		
Variable rates (1.74% at 1/1/16) due 2017		**400**	—		
Total long-term senior notes and debt		**20,418**	19,055		
Other long-term debt —					
Pollution control revenue bonds —					
Maturity	Interest Rates				
2019	4.55%	**25**	25		
2022 through 2049	0.28% to 5.15%	**1,509**	1,466		
Variable rates (0.03% to 0.04% at 1/1/15) due 2015		**—**	152		
Variable rate (0.22% at 1/1/16) due 2016		**4**	4		
Variable rate (0.05% to 0.06% at 1/1/16) due 2017		**36**	36		
Variable rate (0.16% at 1/1/16) due 2020		**7**	7		
Variable rates (0.01% to 0.27% at 1/1/16) due 2021 to 2053		**1,757**	1,559		
Plant Daniel revenue bonds (7.13%) due 2021		**270**	270		
FFB loans —					
3.00% to 3.86% due 2020		**37**	20		
3.00% to 3.86% due 2021 to 2044		**2,163**	1,180		
Junior subordinated notes (6.25%) due 2075		**1,000**	—		
Total other long-term debt		**6,808**	4,719		
Capitalized lease obligations		**146**	159		
Unamortized debt premium		**61**	69		
Unamortized debt discount		**(36)**	(33)		
Unamortized debt issuance expense		**(241)**	(202)		
Total long-term debt (annual interest requirement — $997 million)		**27,362**	23,973		
Less amount due within one year		**2,674**	3,329		
Long-term debt excluding amount due within one year		**24,688**	20,644	**52.6%**	49.2%

	2015	2014	2015	2014
	(in millions)		*(percent of total)*	
Redeemable Preferred Stock of Subsidiaries:				
Cumulative preferred stock				
$100 par or stated value — 4.20% to 5.44%				
Authorized — 20 million shares				
Outstanding — 1 million shares	**81**	81		
$1 par value —				
Authorized — 28 million shares				
Outstanding — $25 stated value	**37**	294		
— 2015: 5.83% — 2 million shares				
— 2014: 5.20% to 5.83% — 12 million shares				
Total redeemable preferred stock of subsidiaries (annual dividend requirement — $6 million)	**118**	375	**0.3**	0.9
Redeemable Noncontrolling Interests	**43**	39	**0.1**	0.1
Common Stockholders' Equity:				
Common stock, par value $5 per share —	**4,572**	4,539		
Authorized — 1.5 billion shares				
Issued — 2015: 915 million shares				
— 2014: 909 million shares				
Treasury — 2015: 3.4 million shares				
— 2014: 0.7 million shares				
Paid-in capital	**6,282**	5,955		
Treasury, at cost	**(142)**	(26)		
Retained earnings	**10,010**	9,609		
Accumulated other comprehensive loss	**(130)**	(128)		
Total common stockholders' equity	**20,592**	19,949	**44.0**	47.5
Preferred and Preference Stock of Subsidiaries and Noncontrolling Interests:				
Non-cumulative preferred stock				
$25 par value — 6.00% to 6.13%				
Authorized — 60 million shares				
Outstanding — 2 million shares	**45**	45		
Preference stock				
Authorized — 65 million shares				
Outstanding — $1 par value	**196**	343		
— 2015: 6.45% to 6.50% — 8 million shares (non-cumulative)				
— 2014: 5.63% to 6.50% — 14 million shares (non-cumulative)				
Outstanding — $100 par or stated value	**368**	368		
— 5.60% to 6.50% — 4 million shares (non-cumulative)				
Noncontrolling Interests	**781**	221		
Total preferred and preference stock of subsidiaries and noncontrolling interests (annual dividend requirement — $39 million)	**1,390**	977	**3.0**	2.3
Total stockholders' equity	**21,982**	20,926		
Total Capitalization	**$ 46,831**	$ 41,984	**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, 2015, 2014, and 2013

	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	Non-controlling Interests	Total
	(in thousands)						*(in millions)*			
Balance at December 31, 2012	877,803	(10,035)	$4,389	$ 4,855	$ (450)	$ 9,626	$ (123)	$ 707	$ —	$ 19,004
Consolidated net income attributable to Southern Company	—	—	—	—	—	1,644	—	—	—	1,644
Other comprehensive income (loss)	—	—	—	—	—	—	48	—	—	48
Stock issued	14,930	4,443	72	441	203	—	—	49	—	765
Stock-based compensation	—	—	—	65	—	—	—	—	—	65
Cash dividends of $2.0125 per share	—	—	—	—	—	(1,762)	—	—	—	(1,762)
Other	—	(55)	—	1	(3)	2	—	—	—	—
Balance at December 31, 2013	892,733	(5,647)	4,461	5,362	(250)	9,510	(75)	756	—	19,764
Consolidated net income attributable to Southern Company	—	—	—	—	—	1,963	—	—	—	1,963
Other comprehensive income (loss)	—	—	—	—	—	—	(53)	—	—	(53)
Stock issued	15,769	4,996	78	501	227	—	—	—	—	806
Stock-based compensation	—	—	—	86	—	—	—	—	—	86
Cash dividends of $2.0825 per share	—	—	—	—	—	(1,866)	—	—	—	(1,866)
Contributions from noncontrolling interests	—	—	—	—	—	—	—	—	221	221
Net income (loss) attributable to noncontrolling interests	—	—	—	—	—	—	—	—	(2)	(2)
Other	—	(74)	—	6	(3)	2	—	—	2	7
Balance at December 31, 2014	**908,502**	**(725)**	**4,539**	**5,955**	**(26)**	**9,609**	**(128)**	**756**	**221**	**20,926**
Consolidated net income attributable to Southern Company	**—**	**—**	**—**	**—**	**—**	**2,367**	**—**	**—**	**—**	**2,367**
Other comprehensive income (loss)	**—**	**—**	**—**	**—**	**—**	**—**	**(2)**	**—**	**—**	**(2)**
Stock issued	**6,571**	**(2,599)**	**33**	**223**	**—**	**—**	**—**	**—**	**—**	**256**
Stock-based compensation	**—**	**—**	**—**	**100**	**—**	**—**	**—**	**—**	**—**	**100**
Stock repurchased, at cost	**—**	**—**	**—**	**—**	**(115)**	**—**	**—**	**—**	**—**	**(115)**
Cash dividends of $2.1525 per share	**—**	**—**	**—**	**—**	**—**	**(1,959)**	**—**	**—**	**—**	**(1,959)**
Preference stock redemptions	**—**	**—**	**—**	**—**	**—**	**—**	**—**	**(150)**	**—**	**(150)**

	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	Non-controlling Interests	Total
	(in thousands)						*(in millions)*			
Contributions from noncontrolling interests	—	—	—	—	—	—	—	—	567	567
Distributions to noncontrolling interests	—	—	—	—	—	—	—	—	(18)	(18)
Net income attributable to noncontrolling interests	—	—	—	—	—	—	—	—	12	12
Other	—	(28)	—	4	(1)	(7)	—	3	(1)	(2)
Balance at December 31, 2015	**915,073**	**(3,352)**	**$4,572**	**$ 6,282**	**$ (142)**	**$ 10,010**	**$ (130)**	**$ 609**	**$ 781**	**$21,982**

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

NOTES TO FINANCIAL STATEMENTS

Index to the Notes to Financial Statements

1. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

General

The Southern Company (Southern Company or the Company) is the parent company of four traditional operating companies, Southern Power, SCS, SouthernLINC Wireless, Southern Company Holdings, Inc. (Southern Holdings), Southern Nuclear, and other direct and indirect subsidiaries. The traditional operating companies – Alabama Power, Georgia Power, Gulf Power, and Mississippi Power – are vertically integrated utilities providing electric service in four Southeastern states. Southern Power constructs, acquires, owns, and manages generation assets, including renewable energy projects, and sells electricity at market-based rates in the wholesale market. SCS, the system service company, provides, at cost, specialized services to Southern Company and its subsidiary companies. SouthernLINC Wireless provides digital wireless communications for use by Southern Company and its subsidiary companies and also markets these services to the public and provides fiber cable services within the Southeast. Southern Holdings is an intermediate holding company subsidiary, primarily for Southern Company's investments in leveraged leases and for other electric services. Southern Nuclear operates and provides services to the Southern Company system's nuclear power plants.

The financial statements reflect Southern Company's investments in the subsidiaries on a consolidated basis. The equity method is used for entities in which the Company has significant influence but does not control and for variable interest entities where the Company has an equity investment but is not the primary beneficiary. Intercompany transactions have been eliminated in consolidation.

The traditional operating companies, Southern Power, and certain of their subsidiaries are subject to regulation by the FERC, and the traditional operating companies are also subject to regulation by their respective state PSCs. As such, each of the company's financial statements reflect the effects of rate regulation in accordance with GAAP and comply with the accounting policies and practices prescribed by their respective commissions. The preparation of financial statements in conformity with GAAP requires the use of estimates, and the actual results may differ from those estimates. Certain prior years' data presented in the financial statements have been reclassified to conform to the current year presentation.

In June 2015, Georgia Power identified an error affecting the billing to a small number of large commercial and industrial customers under a rate plan allowing for variable demand-driven pricing from January 1, 2013 to June 30, 2015. In the second quarter 2015, Georgia Power recorded an out of period adjustment of approximately $75 million to decrease retail revenues, resulting in a decrease to net income of approximately $47 million. Georgia Power evaluated the effects of this error on the interim and annual periods that included the billing error, as well as the current period. Based on an analysis of qualitative and quantitative factors, Georgia Power determined the error was not material to any affected period and, therefore, an amendment of previously filed financial statements was not required.

Recently Issued Accounting Standards

The Financial Accounting Standards Board's (FASB) ASC 606, *Revenue from Contracts with Customers,* revises the accounting for revenue recognition effective for fiscal years beginning after December 15, 2017. Southern Company continues to evaluate the requirements of ASC 606. The ultimate impact of the new standard has not yet been determined.

On April 7, 2015, the FASB issued Accounting Standards Update (ASU) No. 2015-03, *Interest – Imputation of Interest (Subtopic 835-30): Simplifying the Presentation of Debt Issuance Costs* (ASU 2015-03). ASU 2015-03 requires that debt issuance costs related to a recognized debt liability be presented in the balance sheet as a direct deduction from the carrying amount of that debt liability and is effective for fiscal years beginning after December 15, 2015. As permitted, Southern Company elected to early adopt the guidance as of December 31, 2015 and applied its provisions retrospectively to each prior period presented for comparative purposes. The new guidance resulted in an adjustment to the presentation of debt issuance costs as an offset to the related debt balances primarily in long-term debt totaling $202 million as of December 31, 2014. These debt issuance costs were previously presented within unamortized debt issuance expense. Other than the reclassification, the adoption of ASU 2015-03 did not have an impact on the results of operations, cash flows, or financial condition of Southern Company. See Notes 6 and 10 for disclosures impacted by ASU 2015-03.

On May 1, 2015, the FASB issued ASU No. 2015-07, *Fair Value Measurement (Topic 820): Disclosures for Investments in Certain Entities That Calculate Net Asset Value per Share (or Its Equivalent)* (ASU 2015-07), effective for fiscal years beginning after December 15, 2015. As permitted, Southern Company elected to early adopt the guidance as of December 31, 2015 and applied its provisions retrospectively to each prior period presented for comparative purposes. The amendments in ASU 2015-07 remove the requirement to categorize within the fair value hierarchy all investments for which fair value is measured using the net asset value per share practical expedient. In addition, the amendments remove the requirement to make certain disclosures for all investments that are eligible to be measured at fair value using the net asset value per share practical expedient regardless of whether the practical expedient was used. In accordance with ASU 2015-07, previously reported amounts have been conformed to the current presentation. The adoption of ASU 2015-07 had no impact on the results of operations, cash flows, or financial condition of Southern Company. See Notes 2 and 10 for disclosures impacted by ASU 2015-07.

On November 20, 2015, the FASB issued ASU No. 2015-17, *Income Taxes (Topic 740): Balance Sheet Classification of Deferred Taxes* (ASU 2015-17), which simplifies the presentation of deferred income taxes. ASU 2015-17 requires deferred tax assets and liabilities to be presented as non-current in a classified balance sheet and is effective for fiscal years beginning after December 15, 2016, including interim periods within that reporting period. As permitted, Southern Company elected to early adopt the guidance as of December 31, 2015 and applied its provisions retrospectively to each prior period presented for comparative purposes. Prior to the adoption of ASU 2015-17, all deferred income tax assets and liabilities were required to be separated into current and non-current amounts. The new guidance resulted in a reclassification from deferred income taxes, current of $506 million, with $488 million to non-current accumulated deferred income taxes and $18 million to other deferred charges, as well as $2 million from accrued income taxes to non-current accumulated deferred income taxes in Southern Company's December 31, 2014 balance sheet. Other than the reclassification, the adoption of ASU 2015-17 did not have an impact on the results of operations, cash flows, or financial condition of Southern Company. See Note 5 for disclosures impacted by ASU 2015-17.

Regulatory Assets and Liabilities

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

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

	2015	2014	Note
	(in millions)		
Retiree benefit plans	**$ 3,440**	$ 3,469	(a,n)
Deferred income tax charges	**1,514**	1,458	(b)
Asset retirement obligations-asset	**481**	119	(b,n)
Other regulatory assets	**299**	275	(k)
Loss on reacquired debt	**248**	267	(c)
Fuel-hedging-asset	**225**	202	(d,n)
Kemper IGCC regulatory assets	**216**	148	(h)
Vacation pay	**178**	177	(f,n)
Deferred PPA charges	**163**	185	(e,n)
Under recovered regulatory clause revenues	**142**	157	(g)
Remaining net book value of retired assets	**283**	44	(o)
Environmental remediation-asset	**78**	64	(j,n)
Property damage reserves-asset	**92**	98	(i)
Nuclear outage	**88**	99	(g)
Other cost of removal obligations	**(1,177)**	(1,229)	(b)
Over recovered regulatory clause revenues	**(261)**	(48)	(g)
Deferred income tax credits	**(187)**	(192)	(b)
Property damage reserves-liability	**(178)**	(181)	(l)
Asset retirement obligations-liability	**(45)**	(130)	(b,n)
Other regulatory liabilities	**(35)**	(47)	(m)
Mirror CWIP	**—**	(271)	(h)
Total regulatory assets (liabilities), net	**$ 5,564**	$ 4,664	

Note: The recovery and amortization periods for these regulatory assets and (liabilities) are as follows:
(a) Recovered and amortized over the average remaining service period which may range up to 15 years. See Note 2 for additional information.
(b) Asset retirement and removal assets and liabilities are recorded, deferred income tax assets are recovered, and deferred income tax liabilities are amortized over the related property lives, which may range up to 70 years. Asset retirement and removal assets and liabilities will be settled and trued up following completion of the related activities. At December 31, 2015, other cost of removal obligations included $14 million that will be amortized over the twelve months ending December 31, 2016 in accordance with Georgia Power's 2013 ARP.
(c) Recovered over either the remaining life of the original issue or, if refinanced, over the remaining life of the new issue, which may range up to 50 years.
(d) Recorded over the life of the underlying hedged purchase contracts, which generally do not exceed five years. Upon final settlement, actual costs incurred are recovered through the energy cost recovery clause.
(e) Recovered over the life of the PPA for periods up to eight years.
(f) Recorded as earned by employees and recovered as paid, generally within one year. This includes both vacation and banked holiday pay.
(g) Recorded and recovered or amortized as approved or accepted by the appropriate state PSCs over periods not exceeding 10 years.
(h) For additional information, see Note 3 under "Integrated Coal Gasification Combined Cycle – Rate Recovery of Kemper IGCC Costs – Regulatory Assets and Liabilities."
(i) Recorded and recovered or amortized as approved or accepted by the appropriate state PSCs over periods generally not exceeding six years.
(j) Recovered through the environmental cost recovery clause when the remediation is performed.
(k) Comprised of numerous immaterial components including deferred income tax charges - Medicare subsidy, cancelled construction projects, building leases, closure of Plant Scholz ash pond, Plant Daniel Units 3 and 4 regulatory assets, property tax, and other miscellaneous assets. These costs are recorded and recovered or amortized as approved by the appropriate state PSCs over periods generally not exceeding 15 years.
(l) Recovered as storm restoration and potential reliability-related expenses are incurred as approved by the appropriate state PSCs.
(m) Comprised of numerous immaterial components including retiree benefit plans, fuel-hedging gains, and other liabilities that are recorded and recovered or amortized as approved by the appropriate state PSCs generally over periods not exceeding 15 years.
(n) Not earning a return as offset in rate base by a corresponding asset or liability.
(o) Amortized as approved by the appropriate state PSCs over periods not exceeding 11 years.

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

Revenues

Wholesale capacity revenues from PPAs are recognized either on a levelized basis over the appropriate contract period or the amount billable under the contract terms. Energy and other revenues are recognized as services are provided. Unbilled revenues related to retail sales are accrued at the end of each fiscal period. Electric rates for the traditional operating companies include provisions to adjust billings for fluctuations in fuel costs, fuel hedging, the energy component of purchased power costs, and certain other costs. Revenues are adjusted for differences between these actual costs and amounts billed in current regulated rates. Under or over recovered regulatory clause revenues are recorded in the balance sheets and are recovered or returned to customers through adjustments to the billing factors.

Southern Company's electric utility subsidiaries have a diversified base of customers. No single customer or industry comprises 10% or more of revenues. For all periods presented, uncollectible accounts averaged less than 1% of revenues.

Fuel Costs

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

Income and Other Taxes

Southern Company uses the liability method of accounting for deferred income taxes and provides deferred income taxes for all significant income tax temporary differences. Taxes that are collected from customers on behalf of governmental agencies to be remitted to these agencies are presented net on the statements of income. In accordance with regulatory requirements, deferred federal ITCs for the traditional operating companies are amortized over the average lives of the related property with such amortization normally applied as a credit to reduce depreciation in the statements of income. Under current tax law, certain projects at Southern Power are eligible for federal ITCs or cash grants. Southern Power has elected to receive ITCs. The credits are recorded as a deferred credit and are amortized to income tax expense over the life of the asset. Furthermore, the tax basis of the asset is reduced by 50% of the credits received, resulting in a net deferred tax asset. Southern Power has elected to recognize the tax benefit of this basis difference as a reduction to income tax expense in the year in which the plant reaches commercial operation. In addition, certain projects are eligible for federal production tax credits (PTC), which are recorded to income tax expense based on 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 2015 and will be carried forward and utilized in future years. In addition, Southern Company has subsidiaries with various state net operating loss (NOL) carryforwards, which could result in net state income tax benefits in the future, if utilized. See Note 5 to the financial statements for additional information.

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

Property, Plant, and Equipment

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

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

	2015	2014
	(in millions)	
Generation	**$ 41,648**	$ 37,892
Transmission	**10,544**	9,884
Distribution	**17,670**	17,123
General	**4,377**	4,198
Plant acquisition adjustment	**123**	123
Utility plant in service	**74,362**	69,220
Information technology equipment and software	**222**	244
Communications equipment	**418**	439
Other	**116**	110
Other plant in service	**756**	793
Total plant in service	**$ 75,118**	$ 70,013

The cost of replacements of property, exclusive of minor items of property, is capitalized. The cost of maintenance, repairs, and replacement of minor items of property is charged to other operations and maintenance expenses as incurred or performed with the exception of nuclear refueling costs, which are recorded in accordance with specific state PSC orders. Alabama Power and Georgia Power defer and amortize nuclear refueling costs over the unit's operating cycle. The refueling cycles for Alabama Power's Plant Farley and Georgia Power's Plants Hatch and Vogtle Units 1 and 2 range from 18 to 24 months, depending on the unit.

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

	Asset Balances at December 31,	
	2015	2014
	(in millions)	
Office building	**$ 61**	$ 61
Nitrogen plant	**83**	83
Computer-related equipment	**61**	60
Gas pipeline	**6**	6
Less: Accumulated amortization	**(59)**	(49)
Balance, net of amortization	**$ 152**	$ 161

The amount of non-cash property additions recognized for the years ended December 31, 2015, 2014, and 2013 was $844 million, $528 million, and $411 million, respectively. These amounts are comprised of construction-related accounts payable outstanding at each year end. Also, the amount of non-cash property additions associated with capitalized leases for the years ended December 31, 2015, 2014, and 2013 was $13 million, $25 million, and $107 million, respectively.

Depreciation and Amortization

Depreciation of the original cost of utility plant in service is provided primarily by using composite straight-line rates, which approximated 3.0% in 2015, 3.1% in 2014, and 3.3% in 2013. Depreciation studies are conducted periodically to update the composite rates. These studies are filed with the respective state PSC and the FERC for the traditional operating companies. Accumulated depreciation for utility plant in service totaled $23.7 billion and $23.5 billion at December 31, 2015 and 2014, respectively. When property subject to composite depreciation is retired or otherwise disposed of in the normal course of business, its original cost, together with the cost of removal, less salvage, is charged to accumulated depreciation. For other property dispositions, the applicable cost and accumulated depreciation are removed from the balance sheet accounts, and a gain or loss is recognized. Minor items of property included in the original cost of the plant are retired when the related property unit is retired. Certain of Southern Power's generation assets are depreciated on a units-of-production basis, using hours or starts, to better match outage and maintenance costs to the usage of and revenues from these assets. Cost, net of salvage value, of these assets is depreciated on an hours or starts units-of-production basis. Plant in service as of December 31, 2015 and 2014 that is depreciated on a units-of-production basis was approximately $485 million and $470 million, respectively.

Under the terms of Georgia Power's Alternate Rate Plan for the years 2011 through 2013 (2010 ARP) and the 2013 ARP, Georgia Power amortized approximately $31 million in 2013 and $14 million in each of 2014 and 2015 of its remaining regulatory liability related to other cost of removal obligations.

See Note 3 under "Retail Regulatory Matters – Alabama Power – Cost of Removal Accounting Order" and "– Gulf Power – Retail Base Rate Case" for information regarding depreciation and amortization adjustments related to the other cost of removal regulatory liability by Alabama Power and Gulf Power, respectively.

Depreciation of the original cost of other plant in service is provided primarily on a straight-line basis over estimated useful lives ranging from three to 25 years. Accumulated depreciation for other plant in service totaled $510 million and $533 million at December 31, 2015 and 2014, respectively.

Asset Retirement Obligations and Other Costs of Removal

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

The liability for AROs primarily relates to the decommissioning of the Southern Company system's nuclear facilities – Alabama Power's Plant Farley and Georgia Power's Plant Hatch and Plant Vogtle Units 1 and 2 – and facilities that are subject to the Disposal of Coal Combustion Residuals from Electric Utilities final rule published by the EPA on April 17, 2015 (CCR Rule), principally ash ponds. In addition, the Southern Company system has retirement obligations related to various landfill sites, asbestos removal, mine reclamation, and disposal of polychlorinated biphenyls in certain transformers. The Southern Company system also has identified retirement obligations related to certain transmission and distribution facilities, certain wireless communication towers, property associated with the Southern Company system's rail lines and natural gas pipelines, and certain structures authorized by the U.S. Army Corps of Engineers. However, liabilities for the removal of these assets have not been recorded because the settlement timing for the retirement obligations related to these assets is indeterminable and, therefore, the fair value of the retirement obligations cannot be reasonably estimated. A liability for these AROs will be recognized when sufficient information becomes available to support a reasonable estimation of the ARO. The Company will continue to recognize in the statements of income allowed removal costs in accordance with regulatory treatment. Any differences between costs recognized in accordance with accounting standards related to asset retirement and environmental obligations and those reflected in rates are recognized as either a regulatory asset or liability, as ordered by the various state PSCs, and are reflected in the balance sheets. See "Nuclear Decommissioning" herein for additional information on amounts included in rates.

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

	2015	2014
	(in millions)	
Balance at beginning of year	**$ 2,201**	$ 2,018
Liabilities incurred	**662**	18
Liabilities settled	**(37)**	(17)
Accretion	**115**	102
Cash flow revisions	**818**	80
Balance at end of year	$ 3,759	$ 2,201

The increases in liabilities incurred and cash flow revisions in 2015 primarily relate to an increase in AROs associated with facilities impacted by the CCR Rule and Georgia Power's updated nuclear decommissioning study. The cost estimates for AROs related to the CCR Rule are based on information as of December 31, 2015 using various assumptions related to closure and post-closure costs, timing of future cash outlays, inflation and discount rates, and the potential methods for complying with the CCR Rule requirements for closure in place or by other methods. As further analysis is performed, including evaluation of the expected method of compliance, refinement of assumptions underlying the cost estimates, such as the quantities of CCR at each site, and the determination of timing, including the potential for closing ash ponds prior to the end of their currently anticipated useful life, the traditional operating companies expect to continue to periodically update these estimates.

The cash flow revisions in 2014 are primarily related to Alabama Power's and SEGCO's AROs associated with asbestos at their steam generation facilities.

Nuclear Decommissioning

The NRC requires licensees of commercial nuclear power reactors to establish a plan for providing reasonable assurance of funds for future decommissioning. Alabama Power and Georgia Power have external trust funds (Funds) to comply with the NRC's regulations. Use of the Funds is restricted to nuclear decommissioning activities. The Funds are managed and invested in accordance with applicable requirements of various regulatory bodies, including the NRC, the FERC, and state PSCs, as well as the IRS. While Alabama Power and Georgia Power are allowed to prescribe an overall investment policy to the Funds' managers, neither Southern Company nor its subsidiaries or affiliates are allowed to engage in the day-to-day management of the Funds or to mandate individual investment decisions. Day-to-day management of the investments in the Funds is delegated to unrelated third party managers with oversight by the management of Southern Company, Alabama Power, and Georgia Power. The Funds' managers are authorized, within certain investment guidelines, to actively buy and sell securities at their own discretion in order to maximize the return on the Funds' investments. The Funds are invested in a tax-efficient manner in a diversified mix of equity and fixed income securities and are reported as trading securities.

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

The Funds at Georgia Power participate in a securities lending program through the managers of the Funds. Under this program, the Funds' investment securities are loaned to institutional investors for a fee. Securities loaned are fully collateralized by cash, letters of credit, and/or securities issued or guaranteed by the U.S. government or its agencies or instrumentalities. As of December 31, 2015 and 2014, approximately $76 million and $51 million, respectively, of the fair market value of the Funds' securities were on loan and pledged to creditors under the Funds' managers' securities lending program. The fair value of the collateral received was approximately $78 million and $52 million at December 31, 2015 and 2014, respectively, and can only be sold by the borrower upon the return of the loaned securities. The collateral received is treated as a non-cash item in the statements of cash flows.

At December 31, 2015, investment securities in the Funds totaled $1.5 billion, consisting of equity securities of $817 million, debt securities of $654 million, and $38 million of other securities. At December 31, 2014, investment securities in the Funds totaled $1.5 billion, consisting of equity securities of $886 million, debt securities of $638 million, and $19 million of other securities. These amounts include the investment securities pledged to creditors and collateral received and exclude receivables related to investment income and pending investment sales and payables related to pending investment purchases and the lending pool.

Sales of the securities held in the Funds resulted in cash proceeds of $1.4 billion, $913 million, and $1.0 billion in 2015, 2014, and 2013, respectively, all of which were reinvested. For 2015, fair value increases, including reinvested interest and dividends and excluding the Funds' expenses, were $11 million, which included $83 million related to unrealized losses on securities held in the Funds at December 31, 2015. For 2014, fair value increases, including reinvested interest and dividends and excluding the Funds' expenses, were $98 million, which included $19 million related to unrealized gains and losses on securities held in the Funds at December 31, 2014. For 2013, fair value increases, including reinvested interest and dividends and excluding the Funds' expenses, were $181 million, which included $119 million related to unrealized gains on securities held in the Funds at December 31, 2013. While the investment securities held in the Funds are reported as trading securities, the Funds continue to be managed with a long-term focus. Accordingly, all purchases and sales within the Funds are presented separately in the statements of cash flows as investing cash flows, consistent with the nature of the securities and purpose for which the securities were acquired.

For Alabama Power, amounts previously recorded in internal reserves are being transferred into the Funds over periods approved by the Alabama PSC. The NRC's minimum external funding requirements are based on a generic estimate of the cost to decommission only the radioactive portions of a nuclear unit based on the size and type of reactor. 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, 2015 and 2014, the accumulated provisions for decommissioning were as follows:

	External Trust Funds		**Internal Reserves**		**Total**	
	2015	2014	**2015**	2014	**2015**	2014
			(in millions)			
Plant Farley	**$ 734**	$ 754	**$ 20**	$ 21	**$ 754**	$ 775
Plant Hatch	**487**	496	**—**	—	**487**	496
Plant Vogtle Units 1 and 2	**288**	293	**—**	—	**288**	293

Site study cost is the estimate to decommission a specific facility as of the site study year. The decommissioning cost estimates are based on prompt dismantlement and removal of the plant from service. The actual decommissioning costs may vary from these estimates because of changes in the assumed date of decommissioning, changes in NRC requirements, or changes in the assumptions used in making these estimates. The estimated costs of decommissioning as of December 31, 2015 based on the most current studies, which were performed in 2013 for Alabama Power's Plant Farley and in 2015 for the Georgia Power plants, were as follows for Alabama Power's Plant Farley and Georgia Power's ownership interests in Plant Hatch and Plant Vogtle Units 1 and 2:

	Plant Farley	**Plant Hatch**	**Plant Vogtle Units 1 and 2**
Decommissioning periods:			
Beginning year	2037	2034	2047
Completion year	2076	2075	2079
		(in millions)	
Site study costs:			
Radiated structures	$ 1,362	$ 678	$ 568
Spent fuel management	—	160	147
Non-radiated structures	80	64	89
Total site study costs	$ 1,442	$ 902	$ 804

For ratemaking purposes, Alabama Power's decommissioning costs are based on the site study, and Georgia Power's decommissioning costs are based on the NRC generic estimate to decommission the radioactive portion of the facilities and the site study estimate for spent fuel management as of 2012. Under the 2013 ARP, the Georgia PSC approved Georgia Power's annual decommissioning cost through 2016 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 periodically review and adjust, if necessary, the amounts collected in rates for nuclear decommissioning costs. Significant assumptions used to determine these costs for ratemaking were an inflation rate of 4.5% and 2.4% for Alabama Power and Georgia Power, respectively, and a trust earnings rate of 7.0% and 4.4% for Alabama Power and Georgia Power, respectively.

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

Allowance for Funds Used During Construction and Interest Capitalized

In accordance with regulatory treatment, the traditional operating companies 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 from such allowance, AFUDC increases the revenue requirement and is recovered over the service life of the plant through a higher rate base and higher depreciation. The equity component of AFUDC is not included in calculating taxable income. Interest related to the construction of new facilities not included in the traditional operating companies' regulated rates is capitalized in accordance with standard interest capitalization requirements. AFUDC and interest capitalized, net of income taxes were 12.8%, 16.0%, and 15.0% of net income for 2015, 2014, and 2013, respectively.

Cash payments for interest totaled $809 million, $732 million, and $759 million in 2015, 2014, and 2013, respectively, net of amounts capitalized of $124 million, $111 million, and $92 million, respectively.

Impairment of Long-Lived Assets and Intangibles

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

Storm Damage Reserves

Each traditional operating company maintains a reserve to cover or is allowed to defer and recover the cost of damages from major storms to its transmission and distribution lines and generally the cost of uninsured damages to its generation facilities and other property. In accordance with their respective state PSC orders, the traditional operating companies accrued $40 million, $40 million, and $28 million in 2015, 2014, and 2013, respectively. Alabama Power, Gulf Power, and Mississippi Power also have authority based on orders from their state PSCs to accrue certain additional amounts as circumstances warrant. In 2015, 2014, and 2013, there were no such additional accruals. See Note 3 under "Retail Regulatory Matters – Alabama Power – Rate NDR" and "Retail Regulatory Matters – Georgia Power – Storm Damage Recovery" for additional information regarding Alabama Power's NDR and Georgia Power's deferred storm costs, respectively.

Leveraged Leases

Southern Company has several leveraged lease agreements, with original terms ranging up to 45 years, which relate to international and domestic energy generation, distribution, and transportation assets. Southern Company receives federal income tax deductions for depreciation and amortization, as well as interest on long-term debt related to these investments. The Company reviews all important lease assumptions at least annually, or more frequently if events or changes in circumstances indicate that a change in assumptions has occurred or may occur. These assumptions include the effective tax rate, the residual value, the credit quality of the lessees, and the timing of expected tax cash flows.

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

	2015	2014
	(in millions)	
Net rentals receivable	**$ 1,487**	$ 1,495
Unearned income	**(732)**	(752)
Investment in leveraged leases	**755**	743
Deferred taxes from leveraged leases	**(303)**	(299)
Net investment in leveraged leases	**$ 452**	$ 444

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

	2015	2014	2013
		(in millions)	
Pretax leveraged lease income (loss)	**$ 20**	$ 24	$ (5)
Income tax expense	**(7)**	(9)	2
Net leveraged lease income (loss)	**$ 13**	$ 15	$ (3)

Cash and Cash Equivalents

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

Materials and Supplies

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

Fuel Inventory

Fuel inventory includes the average cost of coal, natural gas, oil, transportation, and emissions allowances. Fuel is charged to inventory when purchased and then expensed, at weighted average cost, as used and recovered by the traditional operating companies through fuel cost recovery rates approved by each state PSC. Emissions allowances granted by the EPA are included in inventory at zero cost.

Financial Instruments

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

The Company does not offset fair value amounts recognized for multiple derivative instruments executed with the same counterparty under a master netting arrangement. At December 31, 2015, the amount included in accounts payable in the balance sheets that the Company has recognized for the obligation to return cash collateral arising from derivative instruments was immaterial.

Southern Company is exposed to losses related to financial instruments in the event of counterparties' nonperformance. The Company has established controls to determine and monitor the creditworthiness of counterparties in order to mitigate the Company's exposure to counterparty credit risk.

Comprehensive Income

The objective of comprehensive income is to report a measure of all changes in common stock equity of an enterprise that result from transactions and other economic events of the period other than transactions with owners. Comprehensive income consists of net income, changes in the fair value of qualifying cash flow hedges and marketable securities, certain changes in pension and other postretirement benefit plans, reclassifications for amounts included in net income, and dividends on preferred and preference stock of subsidiaries.

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

	Qualifying Hedges	Marketable Securities	Pension and Other Postretirement Benefit Plans	Accumulated Other Comprehensive Income (Loss)
		(in millions)		
Balance at December 31, 2014	$ (41)	$ —	$ (87)	$ (128)
Current period change	(7)	—	5	(2)
Balance at December 31, 2015	**$ (48)**	**$ —**	**$ (82)**	**$ (130)**

2. RETIREMENT BENEFITS

Southern Company has a defined benefit, trusteed, pension plan covering substantially all employees. This qualified pension plan is funded in accordance with requirements of the Employee Retirement Income Security Act of 1974, as amended (ERISA). No contributions to the qualified pension plan were made for the year ended December 31, 2015, and no mandatory contributions to the qualified pension plan are anticipated for the year ending December 31, 2016. Southern Company also provides certain defined benefit pension plans for a selected group of management and highly compensated employees. Benefits under these non-qualified pension plans are funded on a cash basis. In addition, Southern Company provides certain medical care and life insurance benefits for retired employees through other postretirement benefit plans. The traditional operating companies fund related other postretirement trusts to the extent required by their respective regulatory commissions. For the year ending December 31, 2016, other postretirement trust contributions are expected to total approximately $14 million.

Actuarial Assumptions

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

Assumptions used to determine net periodic costs:	2015	2014	2013
Pension plans			
Discount rate – interest costs	**4.17%**	5.02%	4.26%
Discount rate – service costs	**4.48**	5.02	4.26
Expected long-term return on plan assets	**8.20**	8.20	8.20
Annual salary increase	**3.59**	3.59	3.59
Other postretirement benefit plans			
Discount rate – interest costs	**4.04%**	4.85%	4.05%
Discount rate – service costs	**4.39**	4.85	4.05
Expected long-term return on plan assets	**6.97**	7.15	7.13
Annual salary increase	**3.59**	3.59	3.59

Assumptions used to determine benefit obligations:	2015	2014
Pension plans		
Discount rate	**4.67%**	4.17%
Annual salary increase	**4.46**	3.59
Other postretirement benefit plans		
Discount rate	**4.51%**	4.04%
Annual salary increase	**4.46**	3.59

The Company estimates the expected rate of return on pension plan and other postretirement benefit plan assets using a financial model to project the expected return on each current investment portfolio. The analysis projects an expected rate of return on each of seven different asset classes in order to arrive at the expected return on the entire portfolio relying on each trust's target asset allocation and reasonable capital market assumptions. The financial model is based on four key inputs: anticipated returns by asset class (based in part on historical returns), each trust's target asset allocation, an anticipated inflation rate, and the projected impact of a periodic rebalancing of each trust's portfolio.

For purposes of its December 31, 2015 measurement date, the Company adopted new mortality tables for its pension and other postretirement benefit plans, which reflect decreased life expectancies in the U.S. The adoption of new mortality tables reduced the projected benefit obligations for the Company's pension and other postretirement benefit plans by approximately $191 million and $35 million, respectively.

An additional assumption used in measuring the accumulated other postretirement benefit obligations (APBO) was a weighted average medical care cost trend rate. The weighted average medical care cost trend rates used in measuring the APBO as of December 31, 2015 were as follows:

	Initial Cost Trend Rate	Ultimate Cost Trend Rate	Year That Ultimate Rate is Reached
Pre-65	6.50%	4.50%	2024
Post-65 medical	5.50	4.50	2024
Post-65 prescription	10.00	4.50	2025

An annual increase or decrease in the assumed medical care cost trend rate of 1% would affect the APBO and the service and interest cost components at December 31, 2015 as follows:

	1 Percent Increase	**1 Percent Decrease**
	(in millions)	
Benefit obligation	$ 119	$(102)
Service and interest costs	4	(4)

Pension Plans

The total accumulated benefit obligation for the pension plans was $9.6 billion at December 31, 2015 and $10.0 billion at December 31, 2014. Changes in the projected benefit obligations and the fair value of plan assets during the plan years ended December 31, 2015 and 2014 were as follows:

	2015	2014
	(in millions)	
Change in benefit obligation		
Benefit obligation at beginning of year	**$ 10,909**	$ 8,863
Service cost	**257**	213
Interest cost	**445**	435
Benefits paid	**(487)**	(382)
Actuarial loss (gain)	**(582)**	1,780
Balance at end of year	**10,542**	10,909
Change in plan assets		
Fair value of plan assets at beginning of year	**9,690**	8,733
Actual return (loss) on plan assets	**(14)**	797
Employer contributions	**45**	542
Benefits paid	**(487)**	(382)
Fair value of plan assets at end of year	**9,234**	9,690
Accrued liability	**$ (1,308)**	$ (1,219)

At December 31, 2015, the projected benefit obligations for the qualified and non-qualified pension plans were $10.0 billion and $582 million, respectively. All pension plan assets are related to the qualified pension plan.

Amounts recognized in the balance sheets at December 31, 2015 and 2014 related to the Company's pension plans consist of the following:

	2015	2014
	(in millions)	
Other regulatory assets, deferred	**$ 2,998**	$ 3,073
Other current liabilities	**(46)**	(42)
Employee benefit obligations	**(1,262)**	(1,177)
Accumulated OCI	**125**	134

Presented below are the amounts included in accumulated OCI and regulatory assets at December 31, 2015 and 2014 related to the defined benefit pension plans that had not yet been recognized in net periodic pension cost along with the estimated amortization of such amounts for 2016.

	Prior Service Cost	Net (Gain) Loss
	(in millions)	
Balance at December 31, 2015:		
Accumulated OCI	**$ 3**	**$ 122**
Regulatory assets	**27**	**2,971**
Total	**$ 30**	**$ 3,093**
Balance at December 31, 2014:		
Accumulated OCI	$ 4	$ 130
Regulatory assets	51	3,022
Total	$ 55	$ 3,152
Estimated amortization in net periodic pension cost in 2016:		
Accumulated OCI	**$ 1**	**$ 6**
Regulatory assets	**13**	**145**
Total	**$ 14**	**$ 151**

The components of OCI and the changes in the balance of regulatory assets related to the defined benefit pension plans for the years ended December 31, 2015 and 2014 are presented in the following table:

	Accumulated OCI	Regulatory Assets
	(in millions)	
Balance at December 31, 2013	$ 64	$ 1,651
Net gain	75	1,552
Change in prior service costs	—	1
Reclassification adjustments:		
Amortization of prior service costs	(1)	(25)
Amortization of net gain	(4)	(106)
Total reclassification adjustments	(5)	(131)
Total change	70	1,422
Balance at December 31, 2014	$ 134	$ 3,073
Net loss	**1**	**155**
Reclassification adjustments:		
Amortization of prior service costs	**(1)**	**(24)**
Amortization of net gain	**(9)**	**(206)**
Total reclassification adjustments	**(10)**	**(230)**
Total change	**(9)**	**(75)**
Balance at December 31, 2015	**$ 125**	**$ 2,998**

Components of net periodic pension cost were as follows:

	2015	2014	2013
		(in millions)	
Service cost	**$ 257**	$ 213	$ 232
Interest cost	**445**	435	389
Expected return on plan assets	**(724)**	(645)	(603)
Recognized net loss	**215**	110	200
Net amortization	**25**	26	27
Net periodic pension cost	**$ 218**	$ 139	$ 245

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

Future benefit payments reflect expected future service and are estimated based on assumptions used to measure the projected benefit obligation for the pension plans. At December 31, 2015, estimated benefit payments were as follows:

	Benefit Payments
	(in millions)
2016	$ 450
2017	478
2018	501
2019	527
2020	554
2021 to 2025	3,141

Other Postretirement Benefits

Changes in the APBO and in the fair value of plan assets during the plan years ended December 31, 2015 and 2014 were as follows:

	2015	2014
	(in millions)	
Change in benefit obligation		
Benefit obligation at beginning of year	**$ 1,986**	$ 1,682
Service cost	**23**	21
Interest cost	**78**	79
Benefits paid	**(102)**	(102)
Actuarial loss (gain)	**(38)**	300
Plan amendments	**34**	(2)
Retiree drug subsidy	**8**	8
Balance at end of year	**1,989**	1,986
Change in plan assets		
Fair value of plan assets at beginning of year	**900**	901
Actual return (loss) on plan assets	**(12)**	54

	2015	2014
	(in millions)	
Employer contributions	**39**	39
Benefits paid	**(94)**	(94)
Fair value of plan assets at end of year	**833**	900
Accrued liability	**$ (1,156)**	$ (1,086)

Amounts recognized in the balance sheets at December 31, 2015 and 2014 related to the Company's other postretirement benefit plans consist of the following:

	2015	2014
	(in millions)	
Other regulatory assets, deferred	**$ 433**	$ 387
Other current liabilities	**(4)**	(4)
Employee benefit obligations	**(1,152)**	(1,082)
Other regulatory liabilities, deferred	**(22)**	(21)
Accumulated OCI	**8**	8

Presented below are the amounts included in accumulated OCI and net regulatory assets (liabilities) at December 31, 2015 and 2014 related to the other postretirement benefit plans that had not yet been recognized in net periodic other postretirement benefit cost along with the estimated amortization of such amounts for 2016.

	Prior Service Cost	Net (Gain) Loss
	(in millions)	
Balance at December 31, 2015:		
Accumulated OCI	**$ —**	**$ 8**
Net regulatory assets	**32**	**379**
Total	**$ 32**	**$ 387**
Balance at December 31, 2014:		
Accumulated OCI	$ —	$ 8
Net regulatory assets	2	364
Total	$ 2	$ 372
Estimated amortization as net periodic postretirement benefit cost in 2016:		
Net regulatory assets	**$ 6**	**$ 14**

The components of OCI, along with the changes in the balance of net regulatory assets (liabilities), related to the other postretirement benefit plans for the plan years ended December 31, 2015 and 2014 are presented in the following table:

	Accumulated OCI	Net Regulatory Assets (Liabilities)
	(in millions)	
Balance at December 31, 2013	$ 1	$ 73
Net gain	7	301
Change in prior service costs	—	(2)
Reclassification adjustments:		
Amortization of prior service costs	—	(4)
Amortization of net gain	—	(2)
Total reclassification adjustments	—	(6)
Total change	7	293

	Accumulated OCI	Net Regulatory Assets (Liabilities)
	(in millions)	
Balance at December 31, 2014	$ 8	$ 366
Net gain	—	**33**
Change in prior service costs	—	**33**
Reclassification adjustments:		
Amortization of prior service costs	—	**(4)**
Amortization of net gain	—	**(17)**
Total reclassification adjustments	—	**(21)**
Total change	—	**45**
Balance at December 31, 2015	**$ 8**	**$ 411**

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

	2015	2014	2013
		(in millions)	
Service cost	**$ 23**	$ 21	$ 24
Interest cost	**78**	79	74
Expected return on plan assets	**(58)**	(59)	(56)
Net amortization	**21**	6	21
Net periodic postretirement benefit cost	**$ 64**	$ 47	$ 63

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

	Benefit Payments	Subsidy Receipts	Total
		(in millions)	
2016	$ 123	$ (9)	$ 114
2017	128	(10)	118
2018	133	(11)	122
2019	137	(12)	125
2020	139	(12)	127
2021 to 2025	711	(65)	646

Benefit Plan Assets

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

The composition of the Company's pension plan and other postretirement benefit plan assets as of December 31, 2015 and 2014, along with the targeted mix of assets for each plan, is presented below:

	Target	**2015**	2014
Pension plan assets:			
Domestic equity	26%	**30%**	30%
International equity	25	**23**	23
Fixed income	23	**23**	27
Special situations	3	**2**	1
Real estate investments	14	**16**	14
Private equity	9	**6**	5
Total	100%	**100%**	100%
Other postretirement benefit plan assets:			
Domestic equity	42%	**38%**	41%
International equity	21	**23**	23
Domestic fixed income	24	**26**	26
Global fixed income	4	**4**	3
Special situations	1	**1**	—
Real estate investments	5	**6**	5
Private equity	3	**2**	2
Total	100%	**100%**	100%

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

Investment Strategies

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

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

Benefit Plan Asset Fair Values

Following are the fair value measurements for the pension plan and the other postretirement benefit plan assets as of December 31, 2015 and 2014. The fair values presented are prepared in accordance with GAAP. For purposes of determining the fair value of the pension plan and other postretirement benefit plan assets and the appropriate level designation, management relies on information provided by the plan's trustee. This information is reviewed and evaluated by management with changes made to the trustee information as appropriate.

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

- ***Domestic and international equity.*** Investments in equity securities such as common stocks, American depositary receipts, and real estate investment trusts that trade on a public exchange are classified as Level 1 investments and are valued at the closing price in the active market. Equity investments with unpublished prices (i.e. pooled funds) are valued as Level 2, when the underlying holdings used to value the investment are comprised of Level 1 or Level 2 equity securities.
- ***Fixed income.*** Investments in fixed income securities are generally classified as Level 2 investments and are valued based on prices reported in the market place. Additionally, the value of fixed income securities takes into consideration certain items such as broker quotes, spreads, yield curves, interest rates, and discount rates that apply to the term of a specific instrument.
- ***TOLI.*** Investments in TOLI policies are classified as Level 2 investments and are valued based on the underlying investments held in the policy's separate account. The underlying assets are equity and fixed income pooled funds that are comprised of Level 1 and Level 2 securities.
- ***Real estate investments and private equity.*** Investments in private equity and real estate are generally classified as Level 3 as the underlying assets typically do not have observable inputs. The fund manager values the assets using various inputs and techniques depending on the nature of the underlying investments. In the case of private equity, techniques may include purchase multiples for comparable transactions, comparable public company trading multiples, and discounted cash flow analysis. Real estate managers generally use prevailing market capitalization rates, recent sales of comparable investments, and independent third-party appraisals to value underlying real estate investments. The fair value of partnerships is determined by aggregating the value of the underlying assets.

The fair values of pension plan assets as of December 31, 2015 and 2014 are presented below. These fair value measurements exclude cash, receivables related to investment income, pending investments sales, and payables related to pending investment purchases. Assets that are considered special situations investments, primarily real estate investments and private equities, are presented in the tables below based on the nature of the investment.

	Fair Value Measurements Using				
	Quoted Prices in Active Markets for Identical Assets	Significant Other Observable Inputs	Significant Unobservable Inputs	Net Asset Value as a Practical Expedient	
As of December 31, 2015:	**(Level 1)**	**(Level 2)**	**(Level 3)**	**(NAV)**	**Total**
			(in millions)		
Assets:					
Domestic equity*	$ 1,632	$ 681	$ —	$ —	$ 2,313
International equity*	1,190	990	—	—	2,180
Fixed income:					
U.S. Treasury, government, and agency bonds	—	454	—	—	454
Mortgage- and asset-backed securities	—	199	—	—	199
Corporate bonds	—	1,140	—	—	1,140
Pooled funds	—	500	—	—	500
Cash equivalents and other	—	145	—	—	145
Real estate investments	299	—	—	1,218	1,517
Private equity	—	—	—	635	635
Total	$ 3,121	$ 4,109	$ —	$ 1,853	$ 9,083
Liabilities:					
Derivatives	$ (1)	$ —	$ —	$ —	$ (1)
Total	$ 3,120	$ 4,109	$ —	$ 1,853	$ 9,082

* Level 1 securities consist of actively traded stocks while Level 2 securities consist of pooled funds. Management believes that the portfolio is well-diversified with no significant concentrations of risk.

	Fair Value Measurements Using				
	Quoted Prices in Active Markets for Identical Assets	Significant Other Observable Inputs	Significant Unobservable Inputs	Net Asset Value as a Practical Expedient	
As of December 31, 2014:	**(Level 1)**	**(Level 2)**	**(Level 3)**	**(NAV)**	**Total**
		(in millions)			
Assets:					
Domestic equity*	$ 1,704	$ 704	$ —	$ —	$ 2,408
International equity*	1,070	986	—	—	2,056
Fixed income:					
U.S. Treasury, government, and agency bonds	—	699	—	—	699
Mortgage- and asset-backed securities	—	188	—	—	188
Corporate bonds	—	1,135	—	—	1,135
Pooled funds	—	514	—	—	514
Cash equivalents and other	3	660	—	—	663
Real estate investments	293	—	—	1,121	1,414
Private equity	—	—	—	570	570
Total	$ 3,070	$ 4,886	$ —	$ 1,691	$ 9,647
Liabilities:					
Derivatives	$ (2)	$ —	$ —	$ —	$ (2)
Total	$ 3,068	$ 4,886	$ —	$ 1,691	$ 9,645

* Level 1 securities consist of actively traded stocks while Level 2 securities consist of pooled funds. Management believes that the portfolio is well-diversified with no significant concentrations of risk.

The fair values of other postretirement benefit plan assets as of December 31, 2015 and 2014 are presented below. These fair value measurements exclude cash, receivables related to investment income, pending investments sales, and payables related to pending investment purchases. Assets that are considered special situations investments, primarily real estate investments and private equities, are presented in the tables below based on the nature of the investment.

	Fair Value Measurements Using				
	Quoted Prices in Active Markets for Identical Assets	Significant Other Observable Inputs	Significant Unobservable Inputs	Net Asset Value as a Practical Expedient	
As of December 31, 2015:	**(Level 1)**	**(Level 2)**	**(Level 3)**	**(NAV)**	**Total**
		(in millions)			
Assets:					
Domestic equity*	$ 106	$ 52	$ —	$ —	$ 158
International equity*	40	64	—	—	104
Fixed income:					
U.S. Treasury, government, and agency bonds	—	22	—	—	22
Mortgage- and asset-backed securities	—	7	—	—	7
Corporate bonds	—	38	—	—	38
Pooled funds	—	42	—	—	42
Cash equivalents and other	11	9	—	—	20
Trust-owned life insurance	—	370	—	—	370
Real estate investments	11	—	—	41	52
Private equity	—	—	—	21	21
Total	$ 168	$ 604	$ —	$ 62	$ 834

* Level 1 securities consist of actively traded stocks while Level 2 securities consist of pooled funds. Management believes that the portfolio is well-diversified with no significant concentrations of risk.

As of December 31, 2014:	Quoted Prices in Active Markets for Identical Assets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)	Net Asset Value as a Practical Expedient (NAV)	Total
			(in millions)		
Assets:					
Domestic equity*	$ 147	$ 56	$ —	$ —	$ 203
International equity*	36	67	—	—	103
Fixed income:					
U.S. Treasury, government, and agency bonds	—	29	—	—	29
Mortgage- and asset-backed securities	—	6	—	—	6
Corporate bonds	—	39	—	—	39
Pooled funds	—	41	—	—	41
Cash equivalents and other	9	27	—	—	36
Trust-owned life insurance	—	381	—	—	381
Real estate investments	11	—	—	37	48
Private equity	—	—	—	19	19
Total	$ 203	$ 646	$ —	$ 56	$ 905

(Column group heading: Fair Value Measurements Using)

* Level 1 securities consist of actively traded stocks while Level 2 securities consist of pooled funds. Management believes that the portfolio is well-diversified with no significant concentrations of risk.

Employee Savings Plan

Southern Company also sponsors a 401(k) defined contribution plan covering substantially all employees. The Company provides an 85% matching contribution on up to 6% of an employee's base salary. Total matching contributions made to the plan for 2015, 2014, and 2013 were $92 million, $87 million, and $84 million, respectively.

3. CONTINGENCIES AND REGULATORY MATTERS

General Litigation Matters

Southern Company and its subsidiaries are subject to certain claims and legal actions arising in the ordinary course of business. In addition, the business activities of Southern Company's subsidiaries are subject to extensive governmental regulation related to public health and the environment, such as regulation of air emissions and water discharges. Litigation over environmental issues and claims of various types, including property damage, personal injury, common law nuisance, and citizen enforcement of environmental requirements such as air quality and water standards, has occurred throughout the U.S. This litigation has included claims for damages alleged to have been caused by CO_2 and other emissions, CCR, and alleged exposure to hazardous materials, and/or requests for injunctive relief in connection with such matters. The ultimate outcome of such pending or potential litigation against Southern Company and its subsidiaries cannot be predicted at this time; however, for current proceedings not specifically reported herein, management does not anticipate that the ultimate liabilities, if any, arising from such current proceedings would have a material effect on Southern Company's financial statements.

AGL Resources Merger Litigation

AGL Resources and each member of the AGL Resources board of directors were named as defendants in four purported shareholder class action lawsuits filed in the United States District Court for the Northern District of Georgia in September and October 2015. These actions were filed on behalf of named plaintiffs and other AGL Resources shareholders challenging the Merger and seeking, among other things, preliminary and permanent injunctive relief enjoining the Merger, and, in certain circumstances, damages. Southern Company and Merger Sub were also named as defendants in two of these lawsuits. On October 23, 2015, the court consolidated the four lawsuits into a single action. On January 4, 2016, the parties filed a proposed stipulated order of dismissal, asking the court to dismiss the consolidated amended complaint without prejudice, which the court approved on January 5, 2016. See Note 12 under "Southern Company – Proposed Merger with AGL Resources" for additional information regarding the Merger.

Environmental Matters

Environmental Remediation

The Southern Company system must comply with environmental laws and regulations that cover the handling and disposal of waste and releases of hazardous substances. Under these various laws and regulations, the Southern Company system could incur substantial costs to clean up affected sites. The traditional operating companies have each received authority from their respective state PSCs to recover approved environmental compliance costs through regulatory mechanisms. These rates are adjusted annually or as necessary within limits approved by the state PSCs.

Georgia Power's environmental remediation liability as of December 31, 2015 was $29 million. Georgia Power has been designated or identified as a potentially responsible party (PRP) at sites governed by the Georgia Hazardous Site Response Act and/or by the federal Comprehensive Environmental Response, Compensation, and Liability Act (CERCLA), including a site in Brunswick, Georgia on the CERCLA National Priorities List. The PRPs at the Brunswick site have completed a removal action as ordered by the EPA. Additional response actions at this site are anticipated. In September 2015, Georgia Power entered into an allocation agreement with another PRP, under which that PRP will be responsible (as between Georgia Power and that PRP) for paying and performing certain investigation, assessment, remediation, and other incidental activities at the Brunswick site. Assessment and potential cleanup of other sites are anticipated.

The ultimate outcome of these matters will depend upon the success of defenses asserted, the ultimate number of PRPs participating in the cleanup, and numerous other factors and cannot be determined at this time; however, as a result of Georgia Power's regulatory treatment for environmental remediation expenses, these matters are not expected to have a material impact on Southern Company's financial statements.

Gulf Power's environmental remediation liability includes estimated costs of environmental remediation projects of approximately $46 million as of December 31, 2015. These estimated costs primarily relate to site closure criteria by the Florida Department of Environmental Protection (FDEP) for potential impacts to soil and groundwater from herbicide applications at Gulf Power substations. The schedule for completion of the remediation projects is subject to FDEP approval. The projects have been approved by the Florida PSC for recovery through Gulf Power's environmental cost recovery clause; therefore, these liabilities have no impact on net income.

The final outcome of these matters cannot be determined at this time. However, based on the currently known conditions at these sites and the nature and extent of activities relating to these sites, management does not believe that additional liabilities, if any, at these sites would be material to the financial statements.

Nuclear Fuel Disposal Costs

Acting through the DOE and pursuant to the Nuclear Waste Policy Act of 1982, the U.S. government entered into contracts with Alabama Power and Georgia Power that require the DOE to dispose of spent nuclear fuel and high level radioactive waste generated at Plants Hatch and Farley and Plant Vogtle Units 1 and 2 beginning no later than January 31, 1998. The DOE has yet to commence the performance of its contractual and statutory obligation to dispose of spent nuclear fuel. Consequently, Alabama Power and Georgia Power pursued and continue to pursue legal remedies against the U.S. government for its partial breach of contract.

In December 2014, the Court of Federal Claims entered a judgment in favor of Georgia Power and Alabama Power in their spent nuclear fuel lawsuit seeking damages for the period from January 1, 2005 through December 31, 2010. On March 19, 2015, Georgia Power recovered approximately $18 million, based on its ownership interests, and Alabama Power recovered approximately $26 million. In March 2015, Georgia Power credited the award to accounts where the original costs were charged and reduced rate base, fuel, and cost of service for the benefit of customers. In November 2015, Alabama Power applied the retail-related proceeds to offset the nuclear fuel expense under Rate ECR. See "Retail Regulatory Matters – Alabama Power – Nuclear Waste Fund Accounting Order" herein for additional information. In December 2015, Alabama Power credited the wholesale-related proceeds to each wholesale customer.

In March 2014, Alabama Power and Georgia Power filed additional lawsuits against the U.S. government for the costs of continuing to store spent nuclear fuel at Plants Farley and Hatch and Plant Vogtle Units 1 and 2 for the period from January 1, 2011 through December 31, 2013. The damage period was subsequently extended to December 31, 2014. Damages will continue to accumulate until the issue is resolved or storage is provided. No amounts have been recognized in the financial statements as of December 31, 2015 for any potential recoveries from the additional lawsuits. The final outcome of these matters cannot be determined at this time; however, no material impact on Southern Company's net income is expected.

On-site dry spent fuel storage facilities are operational at all three plants and can be expanded to accommodate spent fuel through the expected life of each plant.

FERC Matters

The traditional operating companies and Southern Power have authority from the FERC to sell electricity at market-based rates. Since 2008, that authority, for certain balancing authority areas, has been conditioned on compliance with the requirements of an energy auction, which the FERC found to be tailored mitigation that addresses potential market power concerns. In accordance with FERC regulations governing such authority, the traditional operating companies and Southern Power filed a triennial market power analysis in June 2014, which included continued reliance on the energy auction as tailored mitigation. On April 27, 2015, the FERC issued an order finding that the traditional operating companies' and Southern Power's existing tailored mitigation may not effectively mitigate the potential to exert market power in certain areas served by the traditional operating companies and in some adjacent areas. The FERC directed the traditional operating companies and Southern Power to show why market-based rate authority should not be revoked in these areas or to provide a mitigation plan to further address market power concerns. The traditional operating companies and Southern Power filed a request for rehearing on May 27, 2015 and on June 26, 2015 filed their response with the FERC. The ultimate outcome of this matter cannot be determined at this time.

Retail Regulatory Matters

Alabama Power

Rate RSE

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

In 2013, the Alabama PSC approved a revision to Rate RSE, effective for calendar year 2014. This revision established the WCE range of 5.75% to 6.21% with an adjusting point of 5.98% and provided eligibility for a performance-based adder of seven basis points, or 0.07%, to the WCE adjusting point if 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.

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

Rate CNP

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

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

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

Rate ECR

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

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

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

Rate NDR

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

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

Environmental Accounting Order

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

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

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

Nuclear Waste Fund Accounting Order

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

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

Cost of Removal Accounting Order

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

Georgia Power

Rate Plans

In 2013, the Georgia PSC voted to approve the 2013 ARP. The 2013 ARP reflects the settlement agreement among Georgia Power, the Georgia PSC's Public Interest Advocacy Staff, and 11 of the 13 intervenors.

In January 2014, in accordance with the 2013 ARP, Georgia Power increased its tariffs as follows: (1) traditional base tariff rates by approximately $80 million; (2) Environmental Compliance Cost Recovery (ECCR) tariff by approximately $25 million; (3) Demand-Side Management (DSM) tariffs by approximately $1 million; and (4) Municipal Franchise Fee (MFF) tariff by approximately $4 million, for a total increase in base revenues of approximately $110 million.

On February 19, 2015, in accordance with the 2013 ARP, the Georgia PSC approved an increase to tariffs effective January 1, 2015 as follows: (1) traditional base tariff rates by approximately $107 million; (2) ECCR tariff by approximately $23 million; (3) DSM tariffs by approximately $3 million; and (4) MFF tariff by approximately $3 million, for a total increase in base revenues of approximately $136 million.

On December 16, 2015, in accordance with the 2013 ARP, the Georgia PSC approved an increase to tariffs effective January 1, 2016 as follows: (1) traditional base tariff rates by approximately $49 million; (2) ECCR tariff by approximately $75 million; (3) DSM tariffs by approximately $3 million; and (4) MFF tariff by approximately $13 million, for a total increase in base revenues of approximately $140 million.

Under the 2013 ARP, Georgia Power's retail ROE is set at 10.95% and earnings are evaluated against a retail ROE range of 10.00% to 12.00%. Two-thirds of any earnings above 12.00% will be directly refunded to customers, with the remaining one-third retained by Georgia Power. There will be no recovery of any earnings shortfall below 10.00% on an actual basis. In 2014, Georgia Power's retail ROE exceeded 12.00%, and Georgia Power will refund to retail customers approximately $11 million in 2016, as approved by the Georgia PSC on February 18, 2016. In 2015, Georgia Power's retail ROE was within the allowed retail ROE range.

Georgia Power is required to file a general base rate case by July 1, 2016, in response to which the Georgia PSC would be expected to determine whether the 2013 ARP should be continued, modified, or discontinued.

Integrated Resource Plan

To comply with the April 16, 2015 effective date of the MATS rule, Plant Branch Units 1, 3, and 4 (1,266 MWs), Plant Yates Units 1 through 5 (579 MWs), and Plant McManus Units 1 and 2 (122 MWs) were retired and operations were discontinued at Plant Mitchell Unit 3 (155 MWs) by April 15, 2015, and Plant Kraft Units 1 through 4 (316 MWs) were retired on October 13, 2015. The switch to natural gas as the primary fuel was completed at Plant Yates Units 6 and 7 by June 2015 and at Plant Gaston Units 1 through 4 by December 2015.

In the 2013 ARP, the Georgia PSC approved the amortization of the CWIP balances related to environmental projects that will not be completed at Plant Branch Units 1 through 4 and Plant Yates Units 6 and 7 over nine years ending December 2022 and the amortization of the remaining net book values of Plant Branch Unit 2 from October 2013 to December 2022, Plant Branch Unit 1 from May 2015 to December 2020, Plant Branch Unit 3 from May 2015 to December 2023, and Plant Branch Unit 4 from May 2015 to December 2024.

On January 29, 2016, Georgia Power filed its triennial IRP (2016 IRP). The filing included a request to decertify Plant Mitchell Units 3, 4A, and 4B (217 MWs) and Plant Kraft Unit 1 (17 MWs) upon approval of the 2016 IRP. The 2016 IRP also reflects that Georgia Power exercised its contractual option to sell its 33% ownership interest in the Intercession City unit (143 MWs total capacity) to Duke Energy Florida, Inc. See Note 4 for additional information.

In the 2016 IRP, Georgia Power requested reclassification of the remaining net book value of Plant Mitchell Unit 3, as of its retirement date, to a regulatory asset to be amortized over a period equal to the unit's remaining useful life. Georgia Power also requested that the Georgia PSC approve the deferral of the cost associated with materials and supplies remaining at the unit retirement dates to a regulatory asset, to be amortized over a period deemed appropriate by the Georgia PSC.

The decertification and retirement of these units are not expected to have a material impact on Southern Company's financial statements; however, the ultimate outcome depends on the Georgia PSC's orders in the 2016 IRP and next general base rate case.

Additionally, the 2016 IRP included a Renewable Energy Development Initiative requesting to procure up to 525 MWs of renewable resources utilizing market-based prices established through a competitive bidding process to expand Georgia Power's existing renewable initiatives, including the Advanced Solar Initiative.

A decision from the Georgia PSC on the 2016 IRP is expected in the third quarter 2016. 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. The Georgia PSC approved a reduction in Georgia Power's total annual billings of approximately $567 million effective June 1, 2012, with an additional $122 million reduction effective January 1, 2013 through June 1, 2014. Under an Interim Fuel Rider, Georgia Power continues to be allowed to adjust its fuel cost recovery rates prior to the next fuel case if the under or over recovered fuel balance exceeds $200 million. Georgia Power's fuel cost recovery includes costs associated with a natural gas hedging program, as approved by the Georgia PSC in 2015, allowing it to use an array of derivative instruments within a 48-month time horizon effective January 1, 2016. See Note 11 under "Energy-Related Derivatives" for additional information. On December 15, 2015, the Georgia PSC approved Georgia Power's request to lower annual billings by approximately $350 million effective January 1, 2016.

Georgia Power's over recovered fuel balance totaled approximately $116 million at December 31, 2015 and is included in current liabilities and other deferred liabilities. At December 31, 2014, Georgia Power's under recovered fuel balance totaled approximately $199 million and was included in current assets and other deferred charges and assets.

Fuel cost recovery revenues as recorded on the financial statements are adjusted for differences in actual recoverable fuel costs and amounts billed in current regulated rates. Accordingly, changes in the billing factor will not have a significant effect on Southern Company's revenues or net income, but will affect cash flow.

Storm Damage Recovery

Georgia Power 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. As of December 31, 2015 and December 31, 2014, the balance in the regulatory asset related to storm damage was $92 million and $98 million, respectively, with approximately $30 million included in other regulatory assets, current for both years and approximately $62 million and $68 million included in other regulatory assets, deferred, respectively. Georgia Power expects the Georgia PSC to periodically review and adjust, if necessary, the amounts collected in rates for storm damage costs. As a result of the regulatory treatment, costs related to storms are generally not expected to have a material impact on Southern Company's financial statements.

Nuclear Construction

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

Under the terms of the Vogtle 3 and 4 Agreement, the Vogtle Owners agreed to pay a purchase price that is subject to certain price escalations and adjustments, including fixed escalation amounts and index-based adjustments, as well as adjustments for change orders, and performance bonuses for early completion and unit performance. The Vogtle 3 and 4 Agreement also provides for liquidated damages upon the Contractor's failure to fulfill the schedule and performance guarantees, subject to a cap. In addition, the Vogtle 3 and 4 Agreement provides for limited cost sharing by the Vogtle Owners for Contractor costs under certain conditions (which have not occurred), with maximum additional capital costs under this provision attributable to Georgia Power (based on Georgia Power's ownership interest) of approximately $114 million. Each Vogtle Owner is severally (and not jointly) liable for its proportionate share, based on its ownership interest, of all amounts owed to the Contractor under the Vogtle 3 and 4 Agreement. Georgia Power's proportionate share is 45.7%.

On December 31, 2015, Westinghouse acquired Stone & Webster, Inc. from CB&I (Acquisition). In connection with the Acquisition, Stone & Webster, Inc. changed its name to WECTEC Global Project Services Inc. (WECTEC). Certain obligations of Westinghouse and Stone & Webster, Inc. have been guaranteed by Toshiba Corporation, Westinghouse's parent company, and CB&I's The Shaw Group Inc., respectively. Subject to the consent of the DOE, in connection with the Acquisition and pursuant to the settlement agreement described below, the guarantee of The Shaw Group Inc. will be terminated. The guarantee of Toshiba Corporation remains in place. In the event of certain credit rating downgrades of any Vogtle Owner, such Vogtle Owner will be required to provide a letter of credit or other credit enhancement. Additionally, on January 13, 2016, as a result of recent credit rating downgrades of Toshiba Corporation, Westinghouse provided the Vogtle Owners with letters of credit in an aggregate amount of $900 million in accordance with, and subject to adjustment under, the terms of the Vogtle 3 and 4 Agreement.

The Vogtle Owners may terminate the Vogtle 3 and 4 Agreement at any time for their convenience, provided that the Vogtle Owners will be required to pay certain termination costs. The Contractor may terminate the Vogtle 3 and 4 Agreement under certain circumstances, including certain Vogtle Owner suspension or delays of work, action by a governmental authority to permanently stop work, certain breaches of the Vogtle 3 and 4 Agreement by the Vogtle Owners, Vogtle Owner insolvency, and certain other events.

In 2009, the NRC issued an Early Site Permit and Limited Work Authorization which allowed limited work to begin on Plant Vogtle Units 3 and 4. The NRC certified the Westinghouse Design Control Document, as amended (DCD), for the AP1000 nuclear reactor design, in late 2011, and issued combined construction and operating licenses (COLs) in early 2012. Receipt of the COLs allowed full construction to begin. There have been technical and procedural challenges to the construction and licensing of Plant Vogtle Units 3 and 4, at the federal and state level, and additional challenges may arise as construction proceeds.

In 2009, the Georgia PSC voted to certify construction of Plant Vogtle Units 3 and 4. In addition, in 2009 the Georgia PSC approved inclusion of the Plant Vogtle Units 3 and 4 related CWIP accounts in rate base, and the State of Georgia enacted the Georgia Nuclear Energy Financing Act, which allows Georgia Power to recover financing costs for nuclear construction projects certified by the Georgia PSC. Financing costs are recovered on all applicable certified costs through annual adjustments to the NCCR tariff by including the related CWIP accounts in rate base during the construction period. The Georgia PSC approved an initial NCCR tariff of approximately $223 million effective January 1, 2011, as well as increases to the NCCR tariff of approximately $35 million, $50 million, $60 million, $27 million, and $19 million effective January 1, 2012, 2013, 2014, 2015, and 2016, respectively.

Georgia Power is required to file semi-annual Vogtle Construction Monitoring (VCM) reports with the Georgia PSC by February 28 and August 31 each year. If the projected construction capital costs to be borne by Georgia Power increase by 5% above the certified cost or the projected in-service dates are significantly extended, Georgia Power is required to seek an amendment to the Plant Vogtle Units 3 and 4 certificate from the Georgia PSC. In February 2013, Georgia Power requested an amendment to the certificate to increase the estimated in-service capital cost of Plant Vogtle Units 3 and 4 from $4.4 billion to $4.8 billion and to extend the estimated in-service dates to the fourth quarter 2017 (from April 2016) and the fourth quarter 2018 (from April 2017) for Plant Vogtle Units 3 and 4, respectively. In October 2013, the Georgia PSC approved a stipulation (2013 Stipulation) between Georgia Power and the Georgia PSC Staff (Staff) to waive the requirement to amend the Plant Vogtle Units 3 and 4 certificate until the completion of Plant Vogtle Unit 3 or earlier if deemed appropriate by the Georgia PSC and Georgia Power.

On April 15, 2015, the Georgia PSC issued a procedural order in connection with the twelfth VCM report, which included a requested amendment (Requested Amendment) to the Plant Vogtle Units 3 and 4 certificate to reflect the Contractor's revised forecast for completion of Plant Vogtle Units 3 and 4 (second quarter of 2019 and second quarter of 2020, respectively) as well as additional estimated Vogtle Owner's costs, of approximately $10 million per month, including property taxes, oversight costs, compliance costs, and other operational readiness costs to include the estimated Vogtle Owner's costs associated with the proposed 18-month Contractor delay and to increase the estimated total in-service capital cost of Plant Vogtle Units 3 and 4 to $5.0 billion. Pursuant to the Georgia PSC's procedural order, the Georgia PSC deemed the Requested Amendment unnecessary and withdrawn until the completion of construction of Plant Vogtle Unit 3 consistent with the 2013 Stipulation. The Georgia PSC recognized that the certified cost and the 2013 Stipulation do not constitute a cost recovery cap. In accordance with the Georgia Integrated Resource Planning Act, any costs incurred by Georgia Power in excess of the certified amount will be included in rate base, provided Georgia Power shows the costs to be reasonable and prudent. Financing costs up to the certified amount will be collected through the NCCR tariff until the units are placed in service and contemplated in a general base rate case, while financing costs on any construction-related costs in excess of the $4.4 billion certified amount are expected to be recovered through AFUDC.

In 2012, the Vogtle Owners and the Contractor commenced litigation regarding the costs associated with design changes to the DCD and the delays in the timing of approval of the DCD and issuance of the COLs, including the assertion by the Contractor that the Vogtle Owners are responsible for these costs under the terms of the Vogtle 3 and 4 Agreement. The Contractor also asserted that it was entitled to extensions of the guaranteed substantial completion dates of April 2016 and April 2017 for Plant Vogtle Units 3 and 4, respectively. In May 2014, the Contractor filed an amended claim alleging that (i) the design changes to the DCD imposed by the NRC delayed module production and the impacts to the Contractor are recoverable by the Contractor under the Vogtle 3 and 4 Agreement and (ii) the changes to the basemat rebar design required by the NRC caused additional costs and delays recoverable by the Contractor under the Vogtle 3 and 4 Agreement. In June 2015, the Contractor updated its estimated damages to an aggregate (based on Georgia Power's ownership interest) of approximately $714 million (in 2015 dollars). The case was pending in the U.S. District Court for the Southern District of Georgia (Vogtle Construction Litigation).

On December 31, 2015, Westinghouse and the Vogtle Owners entered into a definitive settlement agreement (Contractor Settlement Agreement) to resolve disputes between the Vogtle Owners and the Contractor under the Vogtle 3 and 4 Agreement, including the Vogtle Construction Litigation. Effective December 31, 2015, Georgia Power, acting for itself and as agent for the other Vogtle Owners, and the Contractor entered into an amendment to the Vogtle 3 and 4 Agreement to implement the Contractor Settlement Agreement. The Contractor Settlement Agreement and the related amendment to the Vogtle 3 and 4 Agreement (i) restrict the Contractor's ability to seek further increases in the contract price by clarifying and limiting the circumstances that constitute nuclear regulatory changes in law; (ii) provide for enhanced dispute resolution procedures; (iii) revise the guaranteed substantial completion dates to match the current estimated in-service dates of June 30, 2019 for Unit 3 and June 30, 2020 for Unit 4; (iv) provide that delay liquidated damages will now commence from the current estimated nuclear fuel loading date for each unit, which is December 31, 2018 for Unit 3 and December 31, 2019 for Unit 4, rather than the original guaranteed substantial completion dates under the Vogtle 3 and 4 Agreement; and (v) provide that Georgia Power, based on its ownership interest, will pay to the Contractor and capitalize to the project cost approximately $350 million, of which approximately $120 million has been paid previously under the dispute resolution procedures of the Vogtle 3 and 4 Agreement. Further, subsequent to December 31, 2015, Georgia Power paid approximately $121 million under the terms of the Contractor Settlement Agreement. In addition, the Contractor Settlement Agreement provides for the resolution of other open existing items relating to the scope of the project under the Vogtle 3 and 4 Agreement, including cyber security, for which costs were reflected in Georgia Power's previously disclosed in-service cost estimate. Further, as part of the settlement and in connection with the Acquisition: (i) Westinghouse has engaged Fluor Enterprises, Inc., a subsidiary of Fluor Corporation, as a new construction subcontractor; and (ii) the Vogtle Owners, CB&I, and The Shaw Group Inc. have entered into mutual releases of any and all claims arising out of events or circumstances in connection with the construction of Plant Vogtle Units 3 and 4 that occurred on or before the date of the Contractor Settlement Agreement. On January 5, 2016, the Vogtle Construction Litigation was dismissed with prejudice.

On January 21, 2016, Georgia Power submitted the Contractor Settlement Agreement and the related amendment to the Vogtle 3 and 4 Agreement to the Georgia PSC for its review. On February 2, 2016, the Georgia PSC ordered Georgia Power to file supplemental information by April 5, 2016 in support of the Contractor Settlement Agreement and Georgia Power's position that all construction costs to date have been prudently incurred and that the current estimated in-service capital cost and schedule are reasonable. Following Georgia Power's filing under the order, the Staff will conduct a review of all costs incurred related to Plant Vogtle Units 3 and 4, the schedule for completion of Plant Vogtle Units 3 and 4, and the Contractor Settlement Agreement and the Staff is authorized to engage in related settlement discussions with Georgia Power and any intervenors.

The order provides that the Staff is required to report to the Georgia PSC by October 5, 2016 with respect to the status of its review and any settlement-related negotiations. If a settlement with the Staff is reached with respect to costs of Plant Vogtle Units 3 and 4, the Georgia PSC will then conduct a hearing to consider whether to approve that settlement. If a settlement with the Staff is not reached, the Georgia PSC will determine how to proceed, including (i) modifying the 2013 Stipulation, (ii) directing Georgia Power to file a request for an amendment to the certificate for Plant Vogtle Units 3 and 4, (iii) issuing a scheduling order to address remaining disputed issues, or (iv) taking any other option within its authority.

The Georgia PSC has approved thirteen VCM reports covering the periods through June 30, 2015, including construction capital costs incurred, which through that date totaled $3.1 billion. On February 26, 2016, Georgia Power filed its fourteenth VCM report with the Georgia PSC covering the period from July 1 through December 31, 2015. The fourteenth VCM report does not include a requested amendment to the certified cost of Plant Vogtle Units 3 and 4. Georgia Power is requesting approval of $160 million of construction capital costs incurred during that period. Georgia Power anticipates to incur average financing costs of approximately $27 million per month from January 2016 until Plant Vogtle Units 3 and 4 are placed in service. The updated in-service capital cost forecast is $5.44 billion and includes costs related to the Contractor Settlement Agreement. Estimated financing costs during the construction period total approximately $2.4 billion. Georgia Power's CWIP balance for Plant Vogtle Units 3 and 4 was approximately $3.6 billion as of December 31, 2015.

Processes are in place that are designed to assure compliance with the requirements specified in the DCD and the COLs, 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 issues may arise as construction proceeds, which may result in additional license amendments or require other resolution. If any license amendment requests or other licensing-based compliance issues are not resolved in a timely manner, there may be delays in the project schedule that could result in increased costs either to the Vogtle Owners or the Contractor or to both.

As construction continues, the risk remains that challenges with Contractor performance including fabrication, assembly, delivery, and installation of the shield building and structural modules, delays in the receipt of the remaining permits necessary for the operation of Plant Vogtle Units 3 and 4, or other issues could arise and may further impact project schedule and cost. In addition, the IRS allocated production tax credits to each of Plant Vogtle Units 3 and 4, which require the applicable unit to be placed in service before 2021.

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

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

Gulf Power

Retail Base Rate Case

In 2013, the Florida PSC voted to approve a settlement agreement among Gulf Power and all of the intervenors to Gulf Power's retail base rate case (Gulf Power Settlement Agreement). Under the terms of the Gulf Power Settlement Agreement, Gulf Power (1) increased base rates approximately $35 million annually effective January 2014 and subsequently increased base rates approximately $20 million annually effective January 2015; (2) continued its current authorized retail ROE midpoint (10.25%) and range (9.25% – 11.25%); and (3) is accruing a return similar to AFUDC on certain transmission system upgrades placed into service after January 2014 until Gulf Power's next base rate adjustment date or January 1, 2017, whichever comes first.

The Gulf Power Settlement Agreement also includes a self-executing adjustment mechanism that will increase the authorized retail ROE midpoint and range by 25 basis points in the event the 30-year treasury yield rate increases by an average of at least 75 basis points above 3.7947% for a consecutive six-month period.

The Gulf Power Settlement Agreement also provides that Gulf Power may reduce depreciation expense and record a regulatory asset that will be included as an offset to the other cost of removal regulatory liability in an aggregate amount up to $62.5 million between January 2014 and June 2017. In any given month, such depreciation expense reduction may not exceed the amount necessary for the retail ROE, as reported to the Florida PSC monthly, to reach the midpoint of the authorized retail ROE range then in effect. Recovery of the regulatory asset will occur over a period to be determined by the Florida PSC in Gulf Power's next base rate case or next depreciation and dismantlement study proceeding, whichever comes first. For 2015 and 2014, Gulf Power recognized reductions in depreciation expense of $20.1 million and $8.4 million, respectively.

Pursuant to the Gulf Power Settlement Agreement, Gulf Power may not request an increase in its retail base rates to be effective until after June 2017, unless Gulf Power's actual retail ROE falls below the authorized ROE range.

Integrated Coal Gasification Combined Cycle

Kemper IGCC Overview

Construction of Mississippi Power's Kemper IGCC is nearing completion and start-up activities will continue until the Kemper IGCC is placed in service. The Kemper IGCC will utilize an IGCC technology with an output capacity of 582 MWs. The Kemper IGCC will 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 IGCC. The mine, operated by North American Coal Corporation, started commercial operation in 2013. In connection with the Kemper IGCC, Mississippi Power constructed and plans to operate approximately 61 miles of CO_2 pipeline infrastructure for the planned transport of captured CO_2 for use in enhanced oil recovery.

Kemper IGCC Schedule and Cost Estimate

In 2012, the Mississippi PSC issued the 2012 MPSC CPCN Order, a detailed order confirming the CPCN originally approved by the Mississippi PSC in 2010 authorizing the acquisition, construction, and operation of the Kemper IGCC. The certificated cost estimate of the Kemper IGCC included in the 2012 MPSC CPCN Order was $2.4 billion, net of $245 million of grants awarded to the Kemper IGCC project by the DOE under the Clean Coal Power Initiative Round 2 (DOE Grants) and excluding the cost of the lignite mine and equipment, the cost of the CO_2 pipeline facilities, and AFUDC related to the Kemper IGCC. The 2012 MPSC CPCN Order approved a construction cost cap of up to $2.88 billion, with recovery of prudently-incurred costs subject to approval by the Mississippi PSC. The Kemper IGCC was originally projected to be placed in service in May 2014. Mississippi Power placed the combined cycle and the associated common facilities portion of the Kemper IGCC in service using natural gas in August 2014 and currently expects to place the remainder of the Kemper IGCC, including the gasifier and the gas clean-up facilities, in service during the third quarter 2016.

Recovery of the costs subject to the cost cap and the cost of the lignite mine and equipment, the cost of the CO_2 pipeline facilities, AFUDC, and certain general exceptions, including change of law, force majeure, and beneficial capital (which exists when Mississippi Power demonstrates that the purpose and effect of the construction cost increase is to produce efficiencies that will result in a neutral or favorable effect on customers relative to the original proposal for the CPCN) (Cost Cap Exceptions) remains subject to review and approval by the Mississippi PSC. Mississippi Power's Kemper IGCC 2010 project estimate, current cost estimate (which includes the impacts of the Mississippi Supreme Court's (Court) decision), and actual costs incurred as of December 31, 2015, are as follows:

Cost Category	2010 Project Estimate[(f)]	Current Cost Estimate[(a)]	**Actual Costs**
		(in billions)	
Plant Subject to Cost Cap[(b)(g)]	$ 2.40	$ 5.29	**$ 4.83**
Lignite Mine and Equipment	0.21	0.23	**0.23**
CO_2 Pipeline Facilities	0.14	0.11	**0.11**
AFUDC[(c)]	0.17	0.69	**0.59**
Combined Cycle and Related Assets Placed in Service – Incremental[(d)(g)]	—	0.01	**0.01**
General Exceptions	0.05	0.10	**0.09**
Deferred Costs[(e)(g)]	—	0.20	**0.17**
Total Kemper IGCC	$ 2.97	$ 6.63	**$ 6.03**

(a) Amounts in the Current Cost Estimate reflect estimated costs through August 31, 2016.
(b) The 2012 MPSC CPCN Order approved a construction cost cap of up to $2.88 billion, net of the DOE Grants and excluding the Cost Cap Exceptions. The Current Cost Estimate and the Actual Costs include non-incremental operating and maintenance costs related to the combined cycle and associated common facilities placed in service in August 2014 that are subject to the $2.88 billion cost cap and exclude post-in-service costs for the lignite mine. See "Rate Recovery of Kemper IGCC Costs – 2013 MPSC Rate Order" herein for additional information. The Current Cost Estimate and the Actual Costs reflect 100% of the costs of the Kemper IGCC. See note (g) for additional information.
(c) Mississippi Power's original estimate included recovery of financing costs during construction rather than the accrual of AFUDC. This approach was not approved by the Mississippi PSC in 2012 as described in "Rate Recovery of Kemper IGCC Costs." The current estimate reflects the impact of a settlement agreement with the wholesale customers for cost-based rates under FERC's jurisdiction.
(d) Incremental operating and maintenance costs related to the combined cycle and associated common facilities placed in service in August 2014, net of costs related to energy sales. See "Rate Recovery of Kemper IGCC Costs – 2013 MPSC Rate Order" herein for additional information.
(e) The 2012 MPSC CPCN Order approved deferral of non-capital Kemper IGCC-related costs during construction as described in "Rate Recovery of Kemper IGCC Costs – Regulatory Assets and Liabilities" herein.
(f) The 2010 Project Estimate is the certificated cost estimate adjusted to include the certificated estimate for the CO_2 pipeline facilities which was approved in 2011 by the Mississippi PSC.
(g) Beginning in the third quarter 2015, certain costs, including debt carrying costs (associated with assets placed in service and other non-CWIP accounts), that previously were deferred as regulatory assets are now being recognized through income; however, such costs continue to be included in the Current Cost Estimate and the Actual Costs at December 31, 2015.

Of the total costs, including post-in-service costs for the lignite mine, incurred as of December 31, 2015, $3.47 billion was included in property, plant, and equipment (which is net of the DOE Grants and estimated probable losses of $2.41 billion), $2 million in other property and investments, $69 million in fossil fuel stock, $45 million in materials and supplies, $21 million in other regulatory assets, current, $195 million in other regulatory assets, deferred, and $11 million in other deferred charges and assets in the balance sheet.

Mississippi Power does not intend to seek rate recovery for any costs related to the construction of the Kemper IGCC that exceed the $2.88 billion cost cap, net of the DOE Grants and excluding the Cost Cap Exceptions. Southern Company recorded pre-tax charges to income for revisions to the cost estimate above the cost cap of $365 million ($226 million after tax), $868 million ($536 million after tax), and $1.2 billion ($729 million after tax) in 2015, 2014, and 2013, respectively. The increases to the cost estimate in 2015 primarily reflect costs for the extension of the Kemper IGCC's projected in-service date through August 31, 2016, increased efforts related to scope modifications, additional labor costs in support of start-up and operational readiness activities, and system repairs and modifications after startup testing and commissioning activities identified necessary remediation of equipment installation, fabrication, and design issues, including the refractory lining inside the gasifiers; the lignite feed and dryer systems; and the syngas cooler vessels. Any extension of the in-service date beyond August 31, 2016 is currently estimated to result in additional base costs of approximately $25 million to $35 million per month, which includes maintaining necessary levels of start-up labor, materials, and fuel, as well as operational resources required to execute start-up and commissioning activities. However, additional costs may be required for remediation of any further equipment and/or design issues identified. Any extension of the in-service date with respect to the Kemper IGCC beyond August 31, 2016 would also increase costs for the Cost Cap Exceptions, which are not subject to the $2.88 billion cost cap established by the Mississippi PSC. These costs include AFUDC, which is currently estimated to total approximately $13 million per month, as well as carrying costs and operating expenses on Kemper IGCC assets placed in service and consulting and legal fees of approximately $2 million per month. For additional information, see "2015 Rate Case" herein.

Mississippi Power's analysis of the time needed to complete the start-up and commissioning activities for the Kemper IGCC will continue until the remaining Kemper IGCC assets are placed in service. Further cost increases and/or extensions of the in-service date with respect to the Kemper IGCC may result from factors including, but not limited to, labor costs and productivity, adverse weather conditions, shortages and inconsistent quality of equipment, materials, and labor, contractor or supplier delay, non-performance under operating or other agreements, operational readiness, including specialized operator training and required site safety programs, unforeseen engineering or design problems, start-up activities for this first-of-a-kind technology (including major equipment failure and system integration), and/or operational performance (including additional costs to satisfy any operational parameters ultimately adopted by the Mississippi PSC). In subsequent periods, any further changes in the estimated costs to complete construction and start-up of the Kemper IGCC subject to the $2.88 billion cost cap, net of the DOE Grants and excluding the Cost Cap Exceptions, will be reflected in Southern Company's statements of income and these changes could be material.

Rate Recovery of Kemper IGCC Costs

The ultimate outcome of the rate recovery matters discussed herein, including the resolution of legal challenges, determinations of prudency, and the specific manner of recovery of prudently-incurred costs, cannot be determined at this time, but could have a material impact on the Company's results of operations, financial condition, and liquidity.

2012 MPSC CPCN Order

The 2012 MPSC CPCN Order included provisions relating to both Mississippi Power's recovery of financing costs during the course of construction of the Kemper IGCC and Mississippi Power's recovery of costs following the date the Kemper IGCC is placed in service. With respect to recovery of costs following the in-service date of the Kemper IGCC, the 2012 MPSC CPCN Order provided for the establishment of operational cost and revenue parameters based upon assumptions in Mississippi Power's petition for the CPCN. Mississippi Power expects the Mississippi PSC to apply operational parameters in connection with future proceedings related to the operation of the Kemper IGCC. To the extent the Mississippi PSC determines the Kemper IGCC does not meet the operational parameters ultimately adopted by the Mississippi PSC or Mississippi Power incurs additional costs to satisfy such parameters, there could be a material adverse impact on the financial statements.

2013 MPSC Rate Order

In January 2013, Mississippi Power entered into a settlement agreement with the Mississippi PSC that was intended to establish the process for resolving matters regarding cost recovery related to the Kemper IGCC (2013 Settlement Agreement). Under the 2013 Settlement Agreement, Mississippi Power agreed to limit the portion of prudently-incurred Kemper IGCC costs to be included in retail rate base to the $2.4 billion certificated cost estimate, plus the Cost Cap Exceptions, but excluding AFUDC, and any other costs permitted or determined to be excluded from the $2.88 billion cost cap by the Mississippi PSC. In March 2013, the Mississippi PSC issued a rate order approving retail rate increases of 15% effective March 19, 2013 and 3% effective January 1, 2014, which collectively were designed to collect $156 million annually beginning in 2014 (2013 MPSC Rate Order) to be used to mitigate customer rate impacts after the Kemper IGCC is placed in service.

Because the 2013 MPSC Rate Order did not provide for the inclusion of CWIP in rate base as permitted by the Baseload Act, Mississippi Power continues to record AFUDC on the Kemper IGCC. Mississippi Power will not record AFUDC on any additional costs of the Kemper IGCC that exceed the $2.88 billion cost cap, except for Cost Cap Exception amounts.

On February 12, 2015, the Court issued its decision in the legal challenge to the 2013 MPSC Rate Order. The Court reversed the 2013 MPSC Rate Order based on, among other things, its findings that (1) the Mirror CWIP rate treatment was not provided for under the Baseload Act and (2) the Mississippi PSC should have determined the prudence of Kemper IGCC costs before approving rate recovery through the 2013 MPSC Rate Order. The Court also found the 2013 Settlement Agreement unenforceable due to a lack of public notice for the related proceedings. On July 7, 2015, the Mississippi PSC ordered that the Mirror CWIP rate be terminated effective July 20, 2015 and required the fourth quarter 2015 refund of the $342 million collected under the 2013 MPSC Rate Order, along with associated carrying costs of $29 million. The Court's decision did not impact the 2012 MPSC CPCN Order or the February 2013 legislation discussed below.

2015 Rate Case

As a result of the 2015 Court decision, on July 10, 2015, Mississippi Power filed a supplemental filing including a request for interim rates (Supplemental Notice) with the Mississippi PSC which presented an alternative rate proposal (In-Service Asset Proposal) for consideration by the Mississippi PSC. The In-Service Asset Proposal was based upon the test period of June 2015 to May 2016, was designed to recover Mississippi Power's costs associated with the Kemper IGCC assets that are commercially operational and currently providing service to customers (the transmission facilities, combined cycle, natural gas pipeline, and water pipeline) and other related costs, and was designed to collect approximately $159 million annually. On August 13, 2015, the Mississippi PSC approved the implementation of interim rates that became effective with the first billing cycle in September, subject to refund and certain other conditions.

On December 3, 2015, the Mississippi PSC issued an order (In-Service Asset Rate Order) adopting in full a stipulation (the 2015 Stipulation) entered into between Mississippi Power and the MPUS regarding the In-Service Asset Proposal. Consistent with the 2015 Stipulation, the In-Service Asset Rate Order provides for retail rate recovery of an annual revenue requirement of approximately $126 million, based on Mississippi Power's actual average capital structure, with a maximum common equity percentage of 49.733%, a 9.225% return on common equity, and actual embedded interest costs during the test period. The In-Service Asset Rate Order also includes a prudence finding of all costs in the stipulated revenue requirement calculation for the in-service assets. The stipulated revenue requirement excludes the costs of the Kemper IGCC related to the 15% undivided interest that was previously projected to be purchased by SMEPA. See "Termination of Proposed Sale of Undivided Interest to SMEPA" herein for additional information.

With implementation of the new rate on December 17, 2015, the interim rates were terminated and Mississippi Power recorded a customer refund of approximately $11 million in December 2015 for the difference between the interim rates collected and the permanent rates. The refund is required to be completed by March 16, 2016.

Pursuant to the In-Service Asset Rate Order, Mississippi Power is required to file a subsequent rate request within 18 months. As part of the filing, Mississippi Power expects to request recovery of certain costs that the Mississippi PSC had excluded from the revenue requirement calculation.

On February 25, 2016, Greenleaf CO2 Solutions, LLC filed a notice of appeal of the In-Service Asset Rate Order with the Court. Mississippi Power believes the appeal has no merit; however, an adverse outcome in this appeal could have a material impact on Southern Company's results of operations. The ultimate outcome of this matter cannot be determined at this time.

Legislation to authorize a multi-year rate plan and legislation to provide for alternate financing through securitization of up to $1.0 billion of prudently-incurred costs was enacted into law in 2013. Mississippi Power expects to securitize prudently-incurred qualifying facility costs in excess of the certificated cost estimate of $2.4 billion. Qualifying facility costs include, but are not limited to, pre-construction costs, construction costs, regulatory costs, and accrued AFUDC. The Court's decision regarding the 2013 MPSC Rate Order did not impact Mississippi Power's ability to utilize alternate financing through securitization or the February 2013 legislation.

Mississippi Power expects to seek additional rate relief to address recovery of the remaining Kemper IGCC assets. In addition to current estimated costs at December 31, 2015 of $6.63 billion, Mississippi Power anticipates that it will incur additional costs after the Kemper IGCC in-service date until the Kemper IGCC cost recovery approach is finalized. These costs include, but are not limited to, regulatory costs and additional carrying costs which could be material. Recovery of these costs would be subject to approval by the Mississippi PSC.

Mississippi Power expects the Kemper IGCC to qualify for additional DOE grants included in the recently passed Consolidated Appropriations Act of 2015, which are expected to be used to reduce future rate impacts for customers. The ultimate outcome of this matter cannot be determined at this time.

Regulatory Assets and Liabilities

Consistent with the treatment of non-capital costs incurred during the pre-construction period, the Mississippi PSC issued an accounting order in 2011 granting Mississippi Power the authority to defer all non-capital Kemper IGCC-related costs to a regulatory asset through the in-service date, subject to review of such costs by the Mississippi PSC. Such costs include, but are not limited to, carrying costs on Kemper IGCC assets currently placed in service, costs associated with Mississippi PSC and MPUS consultants, prudence costs, legal fees, and operating expenses associated with assets placed in service.

In August 2014, Mississippi Power requested confirmation by the Mississippi PSC of Mississippi Power's authority to defer all operating expenses associated with the operation of the combined cycle subject to review of such costs by the Mississippi PSC. In addition, Mississippi Power is authorized to accrue carrying costs on the unamortized balance of such regulatory assets at a rate and in a manner to be determined by the Mississippi PSC in future cost recovery mechanism proceedings. Beginning in the third quarter 2015, in connection with the implementation of interim rates, Mississippi Power began expensing certain ongoing project costs and certain debt carrying costs (associated with assets placed in service and other non-CWIP accounts) that previously were deferred as regulatory assets and began amortizing certain regulatory assets associated with assets placed in service and consulting and legal fees. The amortization periods for these regulatory assets vary from two years to 10 years as set forth in the In-Service Asset Rate Order. As of December 31, 2015, the balance associated with these regulatory assets was $120 million. Other regulatory assets associated with the remainder of the Kemper IGCC totaled $96 million as of December 31, 2015. The amortization period for these assets is expected to be determined by the Mississippi PSC in future rate proceedings following completion of construction and start-up of the Kemper IGCC and related prudence reviews.

See "2013 MPSC Rate Order" herein for information related to the July 7, 2015 Mississippi PSC order terminating the Mirror CWIP rate and requiring refund of collections under Mirror CWIP.

The In-Service Asset Rate Order requires Mississippi Power to submit an annual true-up calculation of its actual cost of capital, compared to the stipulated total cost of capital, with the first occurring as of May 31, 2016. As of December 31, 2015, Mississippi Power recorded a related regulatory liability of approximately $2 million. See "2015 Rate Case" herein for additional information.

Lignite Mine and CO_2 Pipeline Facilities

In conjunction with the Kemper IGCC, Mississippi Power will own the lignite mine and equipment and has acquired and will continue to acquire mineral reserves located around the Kemper IGCC site. The mine started commercial operation in June 2013.

In 2010, Mississippi Power executed a 40-year management fee contract with Liberty Fuels Company, LLC (Liberty Fuels), a wholly-owned subsidiary of The North American Coal Corporation, which developed, constructed, and is operating and managing the mining operations. The contract with Liberty Fuels is effective through the end of the mine reclamation. As the mining permit holder, Liberty Fuels has a legal obligation to perform mine reclamation and Mississippi Power has a contractual obligation to fund all reclamation activities. In addition to the obligation to fund the reclamation activities, Mississippi Power currently provides working capital support to Liberty Fuels through cash advances for capital purchases, payroll, and other operating expenses.

In addition, Mississippi Power has constructed and will operate the CO_2 pipeline for the planned transport of captured CO_2 for use in enhanced oil recovery. Mississippi Power has entered into agreements with Denbury Onshore (Denbury), a subsidiary of Denbury Resources Inc., and Treetop Midstream Services, LLC (Treetop), an affiliate of Tellus Operating Group, LLC and a subsidiary of Tengrys, LLC, pursuant to which Denbury will purchase 70% of the CO_2 captured from the Kemper IGCC and Treetop will purchase 30% of the CO_2 captured from the Kemper IGCC. The agreements with Denbury and Treetop provide Denbury and Treetop with termination rights as Mississippi Power has not satisfied its contractual obligation to deliver captured CO_2 by May 11, 2015. Since May 11, 2015, Mississippi Power has been engaged in ongoing discussions with its off-takers regarding the status of the CO_2 delivery schedule as well as other issues related to the CO_2 agreements. As a result of discussions with Treetop, on August 3, 2015, Mississippi Power agreed to amend certain provisions of their agreement that do not affect pricing or minimum purchase quantities. Potential requirements imposed on CO_2 off-takers under the Clean Power Plan (if ultimately enacted in its current form, pending resolution of litigation) and the potential adverse financial impact of low oil prices on the off-takers increase the risk that the CO_2 contracts may be terminated or materially modified. Any termination or material modification of these agreements is not expected to have a material impact on Southern Company's revenues. Additionally, if the contracts remain in place, sustained oil price reductions could result in significantly lower revenues than Mississippi Power forecasted to be available to offset customer rate impacts.

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

Termination of Proposed Sale of Undivided Interest to SMEPA

In 2010 and as amended in 2012, Mississippi Power and SMEPA entered into an agreement whereby SMEPA agreed to purchase a 15% undivided interest in the Kemper IGCC. On May 20, 2015, SMEPA notified Mississippi Power that it was terminating the agreement. Mississippi Power had previously received a total of $275 million of deposits from SMEPA that were returned to SMEPA, with interest of approximately $26 million, on June 3, 2015, as a result of the termination by Southern Company, pursuant to its guarantee obligation. Subsequently, Mississippi Power issued a promissory note in the aggregate principal amount of approximately $301 million to Southern Company, which matures December 1, 2017.

The In-Service Asset Proposal and the related rates approved by the Mississippi PSC excluded any costs associated with the 15% undivided interest. Mississippi Power continues to evaluate its alternatives with respect to its investment and the related costs associated with the 15% undivided interest.

Bonus Depreciation

On December 18, 2015, the Protecting Americans from Tax Hikes (PATH) Act was signed into law. Bonus depreciation was extended for qualified property placed in service over the next five years. The PATH Act allows for 50% bonus depreciation for 2015, 2016, and 2017; 40% bonus depreciation for 2018; and 30% bonus depreciation for 2019 and certain long-lived assets placed in service in 2020. The extension of 50% bonus depreciation is expected to result in approximately $3 million of positive cash flows related to the combined cycle and associated common facilities portion of the Kemper IGCC for the 2015 tax year and approximately $360 million for the 2016 tax year, which may not all be realized in 2016 due to a projected NOL on the Company's 2016 income tax return, and is dependent upon placing the remainder of the Kemper IGCC in service in 2016. See "Kemper IGCC Schedule and Cost Estimate" herein for additional information. The ultimate outcome of this matter cannot be determined at this time.

Investment Tax Credits

The IRS allocated $279 million (Phase II) of Internal Revenue Code Section 48A tax credits to Mississippi Power in connection with the Kemper IGCC. These tax credits were dependent upon meeting the IRS certification requirements, including an in-service date no later than April 19, 2016 and the capture and sequestration (via enhanced oil recovery) of at least 65% of the CO_2 produced by the Kemper IGCC during operations in accordance with the Internal Revenue Code. As a result of the schedule extension for the Kemper IGCC, the Phase II tax credits have been recaptured.

Section 174 Research and Experimental Deduction

Southern Company reflected deductions for research and experimental (R&E) expenditures related to the Kemper IGCC in its federal income tax calculations for 2013, 2014, and 2015. In May 2015, Southern Company amended its 2008 through 2013 federal income tax returns to include deductions for Kemper IGCC-related R&E expenditures. Due to the uncertainty related to this tax position, Southern Company had unrecognized tax benefits associated with these R&E deductions totaling approximately $423 million as of December 31, 2015. See "Bonus Depreciation" herein and Note 5 under "Unrecognized Tax Benefits" for additional information. The ultimate outcome of this matter cannot be determined at this time.

4. JOINT OWNERSHIP AGREEMENTS

Alabama Power owns an undivided interest in Units 1 and 2 at Plant Miller and related facilities jointly with PowerSouth Energy Cooperative, Inc. Georgia Power owns undivided interests in Plants Vogtle, Hatch, Wansley, and Scherer in varying amounts jointly with one or more of the following entities: OPC, MEAG Power, the City of Dalton, Georgia, Florida Power & Light Company, and Jacksonville Electric Authority. In addition, Georgia Power has joint ownership agreements with OPC for the Rocky Mountain facilities and with Duke Energy Florida, Inc. for a combustion turbine unit at Intercession City, Florida. Subsequent to December 31, 2015, Georgia Power exercised its contractual option to sell its ownership interest to Duke Energy Florida, Inc. contingent on regulatory approvals. Southern Power owns an undivided interest in Plant Stanton Unit A and related facilities jointly with the Orlando Utilities Commission, Kissimmee Utility Authority, and Florida Municipal Power Agency.

At December 31, 2015, Alabama Power's, Georgia Power's, and Southern Power's percentage ownership and investment (exclusive of nuclear fuel) in jointly-owned facilities in commercial operation with the above entities were as follows:

Facility (Type)	Percent Ownership	Plant in Service	Accumulated Depreciation	CWIP
		(in millions)		
Plant Vogtle (nuclear) Units 1 and 2	45.7%	$ 3,503	$ 2,084	$ 63
Plant Hatch (nuclear)	50.1	1,230	568	90
Plant Miller (coal) Units 1 and 2	91.8	1,518	587	63
Plant Scherer (coal) Units 1 and 2	8.4	260	86	1
Plant Wansley (coal)	53.5	915	290	13
Rocky Mountain (pumped storage)	25.4	181	125	—
Intercession City (combustion turbine)	33.3	13	4	—
Plant Stanton (combined cycle) Unit A	65.0	157	53	—

Georgia Power also owns 45.7% of Plant Vogtle Units 3 and 4 that are currently under construction. See Note 3 under "Retail Regulatory Matters – Georgia Power – Nuclear Construction" for additional information.

Alabama Power and Georgia Power have contracted to operate and maintain their jointly-owned facilities, except for Rocky Mountain and Intercession City, as agents for their respective co-owners. Southern Power has a service agreement with SCS whereby SCS is responsible for the operation and maintenance of Plant Stanton Unit A. The companies' proportionate share of their plant operating expenses is included in the corresponding operating expenses in the statements of income and each company is responsible for providing its own financing.

5. INCOME TAXES

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

Current and Deferred Income Taxes

Details of income tax provisions are as follows:

	2015	2014	2013
		(in millions)	
Federal —			
Current	**$ (177)**	$ 175	$ 363
Deferred	**1,266**	695	386
	1,089	870	749
State —			
Current	**(33)**	93	(10)
Deferred	**138**	14	110
	105	107	100
Total	**$ 1,194**	$ 977	$ 849

Net cash payments (refunds) for income taxes in 2015, 2014, and 2013 were $(9) million, $272 million, and $139 million, respectively.

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

	2015	2014
	(in millions)	
Deferred tax liabilities —		
Accelerated depreciation	**$ 12,767**	$ 11,125
Property basis differences	**1,543**	1,332
Leveraged lease basis differences	**308**	299
Employee benefit obligations	**579**	613
Premium on reacquired debt	**95**	103
Regulatory assets associated with employee benefit obligations	**1,378**	1,390
Regulatory assets associated with AROs	**1,422**	871
Other	**586**	523
Total	**18,678**	16,256
Deferred tax assets —		
Federal effect of state deferred taxes	**479**	430
Employee benefit obligations	**1,720**	1,675
Over recovered fuel clause	**104**	—
Other property basis differences	**695**	453
Deferred costs	**83**	86
ITC carryforward	**742**	480
Unbilled revenue	**111**	67
Other comprehensive losses	**85**	89
AROs	**1,422**	871
Estimated Loss on Kemper IGCC	**451**	631
Deferred state tax assets	**220**	117
Other	**246**	342
Total	**6,358**	5,241
Valuation allowance	**(2)**	(49)
Total deferred tax assets	**6,356**	5,192
Accumulated deferred income taxes	**$ 12,322**	$ 11,064

On November 20, 2015, the FASB issued ASU 2015-17, which simplifies the presentation of deferred income taxes. The new guidance resulted in a reclassification from deferred income taxes, current of $506 million, with $488 million to non-current accumulated deferred income taxes and $18 million to other deferred charges, as well as $2 million from accrued income taxes to non-current accumulated deferred income taxes in Southern Company's December 31, 2014 balance sheet. See Note 1 under "Recently Issued Accounting Standards" for additional information.

The application of bonus depreciation provisions in current tax law has significantly increased deferred tax liabilities related to accelerated depreciation in 2015 and 2014.

At December 31, 2015, Southern Company had subsidiaries with NOL carryforwards for the states of Georgia, Mississippi, New Mexico, and Florida totaling approximately $697 million, $3.0 billion, $133 million, and $115 million, respectively, which could result in net state income tax benefits of $27 million, $97 million, $5 million, and $4 million, respectively, if utilized. These NOLs expire between 2017 and 2035, but are expected to be fully utilized by 2029. During the second quarter 2015, an agreement was reached with the Georgia Department of Revenue that will allow Southern Company to utilize a portion of the NOL carryforward over a four-year period beginning in 2017. Consequently, Southern Company reversed the related valuation allowance and recognized approximately $24 million in net tax benefits. During 2015, approximately $87 million in New Mexico NOLs expired resulting in a $3.5 million net state income tax increase and a corresponding decrease in the valuation allowance, with no tax impact.

At December 31, 2015, the tax-related regulatory assets to be recovered from customers were $1.6 billion. These assets are primarily attributable to tax benefits flowed through to customers in prior years, deferred taxes previously recognized at rates lower than the current enacted tax law, and taxes applicable to capitalized interest.

At December 31, 2015, the tax-related regulatory liabilities to be credited to customers were $187 million. These liabilities are primarily attributable to deferred taxes previously recognized at rates higher than the current enacted tax law and to unamortized ITCs.

In accordance with regulatory requirements, deferred federal ITCs for the traditional operating companies are amortized over the life of the related property with such amortization normally applied as a credit to reduce depreciation in the statements of income. Credits amortized in this manner amounted to $21 million in 2015, $22 million in 2014, and $16 million in 2013. Southern Power's deferred federal ITCs are amortized to income tax expense over the life of the asset. Credits amortized in this manner amounted to $19 million in 2015, $11 million in 2014, and $6 million in 2013. Also, Southern Power received cash related to federal ITCs under the renewable energy incentives of $162 million, $74 million, and $158 million for the years ended December 31, 2015, 2014, and 2013, respectively, which had a material impact on cash flows. Furthermore, the tax basis of the asset is reduced by 50% of the credits received, resulting in a net deferred tax asset. Southern Power has elected to recognize the tax benefit of this basis difference as a reduction to income tax expense in the year in which the plant reaches commercial operation. The tax benefit of the related basis differences reduced income tax expense by $54 million in 2015, $48 million in 2014, and $31 million in 2013.

At December 31, 2015, Southern Company had federal ITC carryforwards which are expected to result in $554 million of federal income tax benefits. The federal ITC carryforwards begin expiring in 2034 but are expected to be fully utilized by 2020. Additionally, Southern Company had state ITC carryforwards for the state of Georgia totaling $188 million, which will expire between 2020 and 2026, but are expected to be fully utilized by 2022.

Effective Tax Rate

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

	2015	2014	2013
Federal statutory rate	**35.0%**	35.0%	35.0%
State income tax, net of federal deduction	**1.9**	2.3	2.5
Employee stock plans dividend deduction	**(1.2)**	(1.4)	(1.6)
Non-deductible book depreciation	**1.2**	1.4	1.5
AFUDC-Equity	**(2.2)**	(2.9)	(2.6)
ITC basis difference	**(1.5)**	(1.6)	(1.2)
Other	**(0.3)**	(0.3)	(0.5)
Effective income tax rate	**32.9%**	32.5%	33.1%

Southern Company's effective tax rate is typically lower than the statutory rate due to its employee stock plans' dividend deduction and non-taxable AFUDC equity.

Unrecognized Tax Benefits

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

	2015	2014	2013
		(in millions)	
Unrecognized tax benefits at beginning of year	**$ 170**	$ 7	$ 70
Tax positions increase from current periods	**43**	64	3
Tax positions increase from prior periods	**240**	102	—
Tax positions decrease from prior periods	**(20)**	(3)	(66)
Balance at end of year	**$ 433**	$ 170	$ 7

The tax positions increase from current periods and prior periods for 2015 and 2014 relate primarily to deductions for R&E expenditures associated with the Kemper IGCC. See Note 3 under "Integrated Coal Gasification Combined Cycle" and "Section 174 Research and Experimental Deduction" herein for more information. The tax positions decrease from prior periods for 2015 and 2014 relates to federal and state income tax credits. The tax positions decrease from prior periods for 2013 relate primarily to the Company's compliance with final U.S. Treasury regulations that resulted in a tax accounting method change for repairs.

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

	2015	2014	2013
		(in millions)	
Tax positions impacting the effective tax rate	**$ 10**	$ 10	$ 7
Tax positions not impacting the effective tax rate	**423**	160	—
Balance of unrecognized tax benefits	**$ 433**	$ 170	$ 7

The tax positions impacting the effective tax rate for 2015, 2014, and 2013 primarily relate to federal and state income tax credits. The tax positions not impacting the effective tax rate for 2015 and 2014 relate to deductions for R&E expenditures associated with the Kemper IGCC. See "Section 174 Research and Experimental Deduction" herein for more information. These amounts are presented on a gross basis without considering the related federal or state income tax impact.

Accrued interest for unrecognized tax benefits was immaterial for all years presented.

Southern Company classifies interest on tax uncertainties as interest expense. Southern Company did not accrue any penalties on uncertain tax positions.

It is reasonably possible that the amount of the unrecognized tax benefits could change within 12 months. The settlement of federal and state audits could impact the balances significantly. At this time, an estimate of the range of reasonably possible outcomes cannot be determined.

The IRS has finalized its audits of Southern Company's consolidated federal income tax returns through 2012. Southern Company has filed its 2013 and 2014 federal income tax returns and has received partial acceptance letters from the IRS; however, the IRS has not finalized its audits. Southern Company is a participant in the Compliance Assurance Process of the IRS. The audits for Southern Company's state income tax returns have either been concluded, or the statute of limitations has expired, for years prior to 2011.

Section 174 Research and Experimental Deduction

Southern Company reduced tax payments for 2015 and included in its 2013 and 2014 consolidated federal income tax returns deductions for R&E expenditures related to the Kemper IGCC. In May 2015, Southern Company amended its 2008 through 2013 federal income tax returns to include deductions for Kemper IGCC-related R&E expenditures.

The Kemper IGCC is based on first-of-a-kind technology, and Southern Company believes that a significant portion of the plant costs qualify as deductible R&E expenditures under Internal Revenue Code Section 174. The IRS is currently reviewing the underlying support for the deduction, but has not completed its audit of these expenditures. Due to the uncertainty related to this tax position, Southern Company had related unrecognized tax benefits associated with these R&E deductions of approximately $423 million and associated interest of $9 million as of December 31, 2015. See Note 3 under "Integrated Coal Gasification Combined Cycle" for additional information regarding the Kemper IGCC. The ultimate outcome of this matter cannot be determined at this time.

6. FINANCING

Long-Term Debt Payable to an Affiliated Trust

Alabama Power has formed a wholly-owned trust subsidiary for the purpose of issuing preferred securities. The proceeds of the related equity investments and preferred security sales were loaned back to Alabama Power through the issuance of junior subordinated notes totaling $206 million as of December 31, 2015 and 2014, which constitute substantially all of the assets of this trust and are reflected in the balance sheets as long-term debt payable. 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, 2015 and 2014, trust preferred securities of $200 million were outstanding.

Securities Due Within One Year

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

	2015	2014
	(in millions)	
Senior notes	**$ 1,810**	$ 2,375
Other long-term debt	**829**	775
Pollution control revenue bonds	**4**	152
Capitalized leases	**32**	31
Unamortized debt issuance expense	**(1)**	(4)
Total	**$ 2,674**	$ 3,329

Maturities through 2020 applicable to total long-term debt are as follows: $2.7 billion in 2016; $2.4 billion in 2017; $1.7 billion in 2018; $1.2 billion in 2019; and $1.4 billion in 2020.

Bank Term Loans

Southern Company and certain of the traditional operating companies have entered into various floating rate bank term loan agreements for loans bearing interest based on one-month LIBOR. At December 31, 2015, Southern Company, Mississippi Power, and Southern Power had outstanding bank term loans totaling $400 million, $900 million, and $400 million, respectively, of which $1.23 billion are reflected in the statements of capitalization as long-term debt and $475 million are reflected in the balance sheet as notes payable. At December 31, 2014, Mississippi Power had outstanding bank term loans totaling $775 million.

In September 2015, Southern Company entered into a $400 million aggregate principal amount 18-month floating rate bank loan bearing interest based on one-month LIBOR. The proceeds were used for working capital and other general corporate purposes.

In April 2015, Mississippi Power entered into two short-term floating rate bank loans with a maturity date of April 1, 2016, in an aggregate principal amount of $475 million, bearing interest based on one-month LIBOR. The proceeds of these loans were used for the repayment of term loans in an aggregate principal amount of $275 million, working capital, and other general corporate purposes, including Mississippi Power's ongoing construction program. Mississippi Power also amended three outstanding floating rate bank loans for an aggregate principal amount of $425 million which, among other things, extended the maturity dates from various dates in 2015 to April 1, 2016.

In August 2015, Southern Power Company entered into a $400 million aggregate principal amount 13-month floating rate bank loan bearing interest based on one-month LIBOR. The proceeds were used for working capital and other general corporate purposes, including Southern Power's growth strategy and continuous construction program.

The outstanding bank loans as of December 31, 2015 have covenants that limit debt levels to a percentage of total capitalization. The percentage is 70% for Southern Company and 65% for Mississippi Power and Southern Power Company, as defined in the agreements. For purposes of these definitions, debt excludes any long-term debt payable to affiliated trusts, other hybrid securities, and, for Southern Company and Mississippi Power, any securitized debt relating to the securitization of certain costs of the Kemper IGCC. Additionally, for Southern Company and Southern Power Company, for purposes of these definitions, debt excludes any project debt incurred by certain subsidiaries of Southern Power Company to the extent such debt is non-recourse to Southern Power Company and capitalization excludes the capital stock or other equity attributable to such subsidiary. At December 31, 2015, each of Southern Company, Mississippi Power, and Southern Power Company was in compliance with its debt limits.

DOE Loan Guarantee Borrowings

Pursuant to the loan guarantee program established under Title XVII of the Energy Policy Act of 2005 (Title XVII Loan Guarantee Program), Georgia Power and the DOE entered into a loan guarantee agreement (Loan Guarantee Agreement) in February 2014, under which the DOE agreed to guarantee the obligations of Georgia Power under a note purchase agreement (FFB Note Purchase Agreement) among the DOE, Georgia Power, and the FFB and a related promissory note (FFB Promissory Note). The FFB Note Purchase Agreement and the FFB Promissory Note provide for a multi-advance term loan facility (FFB Credit Facility), under which Georgia Power may make term loan borrowings through the FFB.

Proceeds of advances made under the FFB Credit Facility are used to reimburse Georgia Power for a portion of certain costs of construction relating to Plant Vogtle Units 3 and 4 that are eligible for financing under the Title XVII Loan Guarantee Program (Eligible Project Costs). Aggregate borrowings under the FFB Credit Facility may not exceed the lesser of (i) 70% of Eligible Project Costs or (ii) approximately $3.46 billion.

All borrowings under the FFB Credit Facility are full recourse to Georgia Power, and Georgia Power is obligated to reimburse the DOE for any payments the DOE is required to make to the FFB under the guarantee. Georgia Power's reimbursement obligations to the DOE are full recourse and secured by a first priority lien on (i) Georgia Power's 45.7% undivided ownership interest in Plant Vogtle Units 3 and 4 (primarily the units under construction, the related real property, and any nuclear fuel loaded in the reactor core) and (ii) Georgia Power's rights and obligations under the principal contracts relating to Plant Vogtle Units 3 and 4. There are no restrictions on Georgia Power's ability to grant liens on other property.

Advances may be requested under the FFB Credit Facility on a quarterly basis through 2020. The final maturity date for each advance under the FFB Credit Facility is February 20, 2044. Interest is payable quarterly and principal payments will begin on February 20, 2020. Borrowings under the FFB Credit Facility will bear interest at the applicable U.S. Treasury rate plus a spread equal to 0.375%.

In February 2014, Georgia Power made initial borrowings under the FFB Credit Facility in an aggregate principal amount of $1.0 billion. The interest rate applicable to $500 million of the initial advance under the FFB Credit Facility is 3.860% for an interest period that extends to 2044 and the interest rate applicable to the remaining $500 million is 3.488% for an interest period that extends to 2029, and is expected to be reset from time to time thereafter through 2044. In connection with its entry into the agreements with the DOE and the FFB, Georgia Power incurred issuance costs of approximately $66 million, which are being amortized over the life of the borrowings under the FFB Credit Facility.

In December 2014, Georgia Power made additional borrowings under the FFB Credit Facility in an aggregate principal amount of $200 million. The interest rate applicable to the $200 million advance in December 2014 under the FFB Credit Facility is 3.002% for an interest period that extends to 2044.

In June and December 2015, Georgia Power made additional borrowings under the FFB Credit Facility in an aggregate principal amount of $600 million and $400 million, respectively. The interest rate applicable to the $600 million principal amount is 3.283% and the interest rate applicable to the $400 million principal amount is 3.072%, both for an interest period that extends to 2044.

Future advances are subject to satisfaction of customary conditions, as well as certification of compliance with the requirements of the Title XVII Loan Guarantee Program, including accuracy of project-related representations and warranties, delivery of updated project-related information, and evidence of compliance with the prevailing wage requirements of the Davis-Bacon Act of 1931, as amended, and certification from the DOE's consulting engineer that proceeds of the advances are used to reimburse Eligible Project Costs.

Under the Loan Guarantee Agreement, Georgia Power is subject to customary borrower affirmative and negative covenants and events of default. In addition, Georgia Power is subject to project-related reporting requirements and other project-specific covenants and events of default.

In the event certain mandatory prepayment events occur, the FFB's commitment to make further advances under the FFB Credit Facility will terminate and Georgia Power will be required to prepay the outstanding principal amount of all borrowings under the FFB Credit Facility over a period of five years (with level principal amortization). Under certain circumstances, insurance proceeds and any proceeds from an event of taking must be applied to immediately prepay outstanding borrowings under the FFB Credit Facility. Georgia Power also may voluntarily prepay outstanding borrowings under the FFB Credit Facility. Under the FFB Promissory Note, any prepayment (whether mandatory or optional) will be made with a make-whole premium or discount, as applicable.

In connection with any cancellation of Plant Vogtle Units 3 and 4 that results in a mandatory prepayment event, the DOE may elect to continue construction of Plant Vogtle Units 3 and 4. In such an event, the DOE will have the right to assume Georgia Power's rights and obligations under the principal agreements relating to Plant Vogtle Units 3 and 4 and to acquire all or a portion of Georgia Power's ownership interest in Plant Vogtle Units 3 and 4.

Senior Notes

Southern Company and its subsidiaries issued a total of $3.7 billion of senior notes in 2015. Southern Company issued $600 million and its subsidiaries issued a total of $3.1 billion. The proceeds of these issuances were used to repay long-term indebtedness, to repay short-term indebtedness, and for other general corporate purposes, including the applicable subsidiaries' continuous construction programs, and, for Southern Power, its growth strategy.

At December 31, 2015 and 2014, Southern Company and its subsidiaries had a total of $19.1 billion and $18.2 billion, respectively, of senior notes outstanding. At December 31, 2015 and 2014, Southern Company had a total of $2.4 billion and $2.2 billion, respectively, of senior notes outstanding.

Subsequent to December 31, 2015, Alabama Power issued $400 million aggregate principal amount of Series 2016A 4.30% Senior Notes due January 2, 2046. The proceeds were used to repay at maturity $200 million aggregate principal amount of its Series FF 5.20% Senior Notes due January 15, 2016 and for general corporate purposes.

Since Southern Company is a holding company, the right of Southern Company and, hence, the right of creditors of Southern Company (including holders of Southern Company senior notes) to participate in any distribution of the assets of any subsidiary of Southern Company, whether upon liquidation, reorganization or otherwise, is subject to prior claims of creditors and preferred and preference stockholders of such subsidiary.

Junior Subordinated Notes

In October 2015, Southern Company issued $1.0 billion aggregate principal amount of Series 2015A 6.25% Junior Subordinated Notes due October 15, 2075. The proceeds were used to pay a portion of Southern Company's outstanding short-term indebtedness and for other general corporate purposes.

Pollution Control Revenue Bonds

Pollution control obligations represent loans to the traditional 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 obligations represent obligations under installment sales agreements with respect to facilities constructed with the proceeds of pollution control bonds issued by public authorities. The traditional operating companies had $3.3 billion and $3.2 billion of outstanding pollution control revenue bonds at December 31, 2015 and December 31, 2014, respectively. The traditional operating companies are required to make payments sufficient for the authorities to meet principal and interest requirements of such bonds. Proceeds from certain issuances are restricted until qualifying expenditures are incurred.

Plant Daniel Revenue Bonds

In 2011, in connection with Mississippi Power's election under its operating lease of Plant Daniel Units 3 and 4 to purchase the assets, Mississippi Power assumed the obligations of the lessor related to $270 million aggregate principal amount of Mississippi Business Finance Corporation Taxable Revenue Bonds, 7.13% Series 1999A due October 20, 2021, issued for the benefit of the lessor. See "Assets Subject to Lien" herein for additional information.

Other Revenue Bonds

Other revenue bond obligations represent loans to Mississippi Power from a public authority of funds derived from the sale by such authority of revenue bonds issued to finance a portion of the costs of constructing the Kemper IGCC and related facilities.

Mississippi Power had $50 million of such obligations outstanding related to tax-exempt revenue bonds at December 31, 2015 and 2014. Such amounts are reflected in the statements of capitalization as long-term senior notes and debt.

Capital Leases

Assets acquired under capital leases are recorded in the balance sheets as utility plant in service and the related obligations are classified as long-term debt.

In 2013, Mississippi Power entered into a nitrogen supply agreement for the air separation unit of the Kemper IGCC, which resulted in a capital lease obligation at December 31, 2015 and 2014 of approximately $77 million and $80 million, respectively, with an annual interest rate of 4.9% for both years. Amortization of the capital lease asset for the air separation unit will begin when the Kemper IGCC is placed in service.

At December 31, 2015 and 2014, the capitalized lease obligations for Georgia Power's corporate headquarters building were $35 million and $40 million, respectively, with an annual interest rate of 7.9% for both years.

At December 31, 2015 and 2014, Alabama Power had a capitalized lease obligation of $5 million for a natural gas pipeline with an annual interest rate of 6.9%.

At December 31, 2015 and 2014, a subsidiary of Southern Company had capital lease obligations of approximately $30 million and $34 million, respectively, for certain computer equipment including desktops, laptops, servers, printers, and storage devices with annual interest rates that range from 1.2% to 3.1%.

Other Obligations

In 2012, January 2014, and October 2014, Mississippi Power received $150 million, $75 million, and $50 million, respectively, interest-bearing refundable deposits from SMEPA to be applied to the sale price for the pending sale of an undivided interest in the Kemper IGCC. In 2013, Southern Company entered into an agreement with SMEPA under which Southern Company agreed to guarantee the obligations of Mississippi Power with respect to any required refund of the deposits. On May 20, 2015, SMEPA notified Mississippi Power of its termination of the asset purchase agreement between Mississippi Power and SMEPA. On June 3, 2015, Southern Company, pursuant to its guarantee obligation, returned approximately $301 million to SMEPA. Subsequently, Mississippi Power issued a promissory note in the aggregate principal amount of approximately $301 million to Southern Company, which matures on December 1, 2017.

Assets Subject to Lien

Each of Southern Company's subsidiaries is organized as a legal entity, separate and apart from Southern Company and its other subsidiaries. There are no agreements or other arrangements among the Southern Company system companies under which the assets of one company have been pledged or otherwise made available to satisfy obligations of Southern Company or any of its other subsidiaries.

Gulf Power has granted one or more liens on certain of its property in connection with the issuance of certain series of pollution control revenue bonds with an aggregate outstanding principal amount of $41 million as of December 31, 2015.

The revenue bonds assumed in conjunction with Mississippi Power's purchase of Plant Daniel Units 3 and 4 are secured by Plant Daniel Units 3 and 4 and certain related personal property. See "Plant Daniel Revenue Bonds" herein for additional information.

See "DOE Loan Guarantee Borrowings" above for information regarding certain borrowings of Georgia Power that are secured by a first priority lien on (i) Georgia Power's 45.7% undivided ownership interest in Plant Vogtle Units 3 and 4 (primarily the units under construction, the related real property, and any nuclear fuel loaded in the reactor core) and (ii) Georgia Power's rights and obligations under the principal contracts relating to Plant Vogtle Units 3 and 4.

Each of the Project Credit Facilities (defined below) is secured by the membership interests and assets of the subsidiary of Southern Power Company party to the agreement. See Note 12 under "Southern Power" for additional information.

Bank Credit Arrangements

At December 31, 2015, committed credit arrangements with banks were as follows:

	Expires						Executable Term Loans		Due Within One Year	
Company	2016	2017	2018	2020	Total	Unused	One Year	Two Years	Term Out	No Term Out
	(in millions)				*(in millions)*		*(in millions)*		*(in millions)*	
Southern Company[(a)]	$ —	$ —	$ 1,000	$ 1,250	$ 2,250	$ 2,250	$ —	$ —	$ —	$ —
Alabama Power	40	—	500	800	1,340	1,340	—	—	—	40
Georgia Power	—	—	—	1,750	1,750	1,732	—	—	—	—
Gulf Power	80	30	165	—	275	275	50	—	50	30
Mississippi Power	220	—	—	—	220	195	30	15	45	175
Southern Power[(b)]	—	—	—	600	600	566	—	—	—	—
Other	70	—	—	—	70	70	—	—	—	70
Total	$ 410	$ 30	$ 1,665	$ 4,400	$ 6,505	$ 6,428	$ 80	$ 15	$ 95	$ 315

(a) Excludes the $8.1 billion Bridge Agreement entered into in September 2015 that will be funded only to the extent necessary to provide financing for the Merger as discussed herein.
(b) Excludes credit agreements (Project Credit Facilities) assumed with the acquisition of certain solar facilities, which are non-recourse to Southern Power Company, the proceeds of which are being used to finance project costs related to such solar facilities currently under construction. See Note 12 under "Southern Power" for additional information.

As reflected in the table above, in August 2015, Southern Company, Alabama Power, Georgia Power, and Southern Power Company each amended and restated their multi-year credit arrangements, which, among other things, extended the maturity dates from 2018 to 2020. Southern Company and Southern Power Company increased their borrowing ability under these arrangements to $1.25 billion from $1.0 billion and to $600 million from $500 million, respectively. Georgia Power increased its borrowing ability by $150 million under its facility maturing in 2020 and terminated its aggregate $150 million facilities maturing in 2016. In September 2015, Southern Company entered into an additional multi-year credit arrangement for $1.0 billion with a maturity date of 2018. Alabama Power entered into a new $500 million three-year credit arrangement which replaced a majority of Alabama Power's bilateral credit arrangements. In November 2015, Gulf Power amended and restated certain of its multi-year credit arrangements which, among other things, extended the maturity dates for the majority of Gulf Power's agreements from 2016 to 2018.

Most of the bank credit arrangements require payment of commitment fees based on the unused portion of the commitments or the maintenance of compensating balances with the banks. Commitment fees average less than 1/4 of 1% for Southern Company, the traditional operating companies, and Southern Power Company. 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 credit arrangements contain covenants that limit debt level to 70% of total capitalization, as defined in the agreements, and most of these other bank credit arrangements contain covenants that limit debt levels to 65% of total capitalization, as defined in the agreements. For purposes of these definitions, debt excludes the long-term debt payable to affiliated trusts and, in certain arrangements, other hybrid securities, and, for Southern Company and Mississippi Power, any securitized debt relating to the securitization of certain costs of the Kemper IGCC. Additionally, for Southern Company and Southern Power Company, for purposes of these definitions, debt excludes any project debt incurred by certain subsidiaries of Southern Power Company to the extent such debt is non-recourse to Southern Power Company and capitalization excludes the capital stock or other equity attributable to such subsidiaries. At December 31, 2015, Southern Company, the traditional operating companies, and Southern Power Company were each in compliance with their respective debt limit covenants.

A portion of the $6.4 billion unused credit with banks is allocated to provide liquidity support to the traditional operating companies' pollution control revenue bonds and commercial paper programs. The amount of variable rate pollution control revenue bonds outstanding requiring liquidity support as of December 31, 2015 was approximately $1.8 billion. In addition, at December 31, 2015, the traditional operating companies had approximately $181 million of fixed rate pollution control revenue bonds outstanding that were required to be remarketed within the next 12 months.

In addition, Southern Company entered into the $8.1 billion Bridge Agreement on September 30, 2015 to provide financing for the Merger in the event long-term financing is not available. The Bridge Agreement provides for total loan commitments in an aggregate amount of $8.1 billion to fund the payment of the cash consideration payable under the Merger Agreement and other cash payments required in connection with the consummation of the Merger, the Bridge Agreement and the borrowings thereunder, the other financing transactions related to the Merger, and the payment of fees and expenses incurred in connection with the foregoing. If funded, the loan under the Bridge Agreement will mature and be payable in full on the date that is 364 days after the funding of the commitments under the Bridge Agreement. As of December 31, 2015, Southern Company had no outstanding loans under the Bridge Agreement. See Note 12 under "Southern Company – Proposed Merger with AGL Resources" for additional information regarding the Merger.

Southern Company, the traditional operating companies, and Southern Power Company make short-term borrowings primarily through commercial paper programs that have the liquidity support of the committed bank credit arrangements described above, excluding the Bridge Agreement. Southern Company, the traditional operating companies, and Southern Power may also borrow through various other arrangements with banks. Commercial paper and short-term bank term loans are included in notes payable in the balance sheets.

Details of short-term borrowings were as follows:

	Short-term Debt at the End of the Period	
	Amount Outstanding	**Weighted Average Interest Rate**
	(in millions)	
December 31, 2015:		
Commercial paper	**$ 740**	**0.7%**
Short-term bank debt	**500**	**1.4%**
Total	**$ 1,240**	**0.9%**
December 31, 2014:		
Commercial paper	$ 803	0.3%
Short-term bank debt	—	—%
Total	$ 803	0.3%

In addition to the short-term borrowings in the table above, the Project Credit Facilities had total amounts outstanding as of December 31, 2015 of $137 million at a weighted average interest rate of 2.0%.

Redeemable Preferred Stock of Subsidiaries

Each of the traditional operating companies has issued preferred and/or preference stock. The preferred stock of Alabama Power and Mississippi Power contains a feature that allows the holders to elect a majority of such subsidiary's board of directors if preferred dividends are not paid for four consecutive quarters. Because such a potential redemption-triggering event is not solely within the control of Alabama Power and Mississippi Power, this preferred stock is presented as "Redeemable Preferred Stock of Subsidiaries" in a manner consistent with temporary equity under applicable accounting standards. The preferred and preference stock at Georgia Power and the preference stock at Alabama Power and Gulf Power do not contain such a provision. As a result, under applicable accounting standards, the preferred and preference stock at Georgia Power and the preference stock at Alabama Power and Gulf Power are presented as "noncontrolling interests," a separate component of "Stockholders' Equity," on Southern Company's balance sheets, statements of capitalization, and statements of stockholders' equity.

At December 31, 2015, the outstanding redeemable preferred stock of subsidiaries of Southern Company was $118 million. At December 31, 2014 and 2013, the outstanding redeemable preferred stock of subsidiaries of Southern Company was $375 million.

In May 2015, Alabama Power redeemed 6.48 million shares ($162 million aggregate stated capital) of its 5.20% Class A Preferred Stock at a redemption price of $25 per share plus accrued and unpaid dividends to the redemption date and 4.0 million shares ($100 million aggregate stated capital) of its 5.30% Class A Preferred Stock at a redemption price of $25 per share plus accrued and unpaid dividends to the redemption date. Additionally, $5 million of issuance costs were transferred from redeemable preferred stock of subsidiaries to common stockholder's equity upon redemption.

7. COMMITMENTS

Fuel and Purchased Power Agreements

To supply a portion of the fuel requirements of the generating plants, the Southern Company system has entered into various long-term commitments for the procurement and delivery of fossil and nuclear fuel which are not recognized on the balance sheets. In 2015, 2014, and 2013, the traditional operating companies and Southern Power incurred fuel expense of $4.8 billion, $6.0 billion, and $5.5 billion, respectively, the majority of which was purchased under long-term commitments. Southern Company expects that a substantial amount of the Southern Company system's future fuel needs will continue to be purchased under long-term commitments.

In addition, the Southern Company system has entered into various long-term commitments for the purchase of capacity and electricity, some of which are accounted for as operating leases or have been used by a third party to secure financing. Total capacity expense under PPAs accounted for as operating leases was $227 million, $198 million, and $157 million for 2015, 2014, and 2013, respectively.

Estimated total obligations under these commitments at December 31, 2015 were as follows:

	Operating Leases (*)	Other
	(in millions)	
2016	$ 233	$ 10
2017	242	8
2018	246	7
2019	249	8
2020	246	4
2021 and thereafter	1,291	47
Total	$ 2,507	$ 84

(*) A total of $304 million of biomass PPAs included under operating leases is contingent upon the counterparties meeting specified contract dates for commercial operation and may change as a result of regulatory action.

Operating Leases

The Southern Company system has operating lease agreements with various terms and expiration dates. Total rent expense was $130 million, $118 million, and $123 million for 2015, 2014, and 2013, respectively. Southern Company includes any step rents, escalations, and lease concessions in its computation of minimum lease payments, which are recognized on a straight-line basis over the minimum lease term.

As of December 31, 2015, estimated minimum lease payments under operating leases were as follows:

	Minimum Lease Payments		
	Barges & Railcars	Other	Total
		(in millions)	
2016	$ 40	$ 81	$ 121
2017	25	78	103
2018	14	67	81
2019	6	55	61
2020	6	47	53
2021 and thereafter	16	690	706
Total	$ 107	$ 1,018	$ 1,125

For the traditional operating companies, a majority of the barge and railcar lease expenses are recoverable through fuel cost recovery provisions. In addition to the above rental commitments, Alabama Power and Georgia Power have obligations upon expiration of certain leases with respect to the residual value of the leased property. These leases have terms expiring through 2024 with maximum obligations under these leases of $48 million. At the termination of the leases, the lessee may renew the lease or exercise its purchase option or the property can be sold to a third party. Alabama Power and Georgia Power expect that the fair market value of the leased property would substantially reduce or eliminate the payments under the residual value obligations.

Guarantees

In 2013, Georgia Power entered into an agreement that requires Georgia Power to guarantee certain payments of a gas supplier for Plant McIntosh for a period up to 15 years. The guarantee is expected to be terminated if certain events occur within one year of the initial gas deliveries in 2017. In the event the gas supplier defaults on payments, the maximum potential exposure under the guarantee is approximately $43 million.

As discussed above under "Operating Leases," Alabama Power and Georgia Power have entered into certain residual value guarantees.

8. COMMON STOCK

Stock Issued

During 2015, Southern Company issued approximately 6.6 million shares of common stock primarily through the Omnibus Incentive Compensation Plan and received proceeds of approximately $256 million. During the first nine months of 2015, all sales under the Southern Investment Plan and the Employee Savings Plan were funded with shares acquired on the open market by independent plan administrators. In October 2015, Southern Company began issuing shares of common stock through the Southern Investment Plan and the Employee Savings Plan. The Company may satisfy its obligations with respect to the plans in several ways, including through using newly issued shares or treasury shares or acquiring shares on the open market through the independent plan administrators.

On March 2, 2015, Southern Company announced a program to repurchase up to 20 million shares of Southern Company common stock to offset all or a portion of the incremental shares issued under its employee and director stock plans, including through stock option exercises, until December 31, 2017. Repurchases may be made by means of open market purchases, privately negotiated transactions, or accelerated or other share repurchase programs, in accordance with applicable securities laws. Under this program, approximately 2.6 million shares were repurchased in 2015 at a total cost of approximately $115 million. No further repurchases under the program are anticipated.

Shares Reserved

At December 31, 2015, a total of 106 million shares were reserved for issuance pursuant to the Southern Investment Plan, the Employee Savings Plan, the Outside Directors Stock Plan, and the Omnibus Incentive Compensation Plan (which includes stock options and performance share units as discussed below). Of the total 106 million shares reserved, there were 14 million shares of common stock remaining available for awards under the Omnibus Incentive Compensation Plan as of December 31, 2015.

Stock-Based Compensation

Stock-based compensation, in the form of stock options and performance share units, may be granted through the Omnibus Incentive Compensation Plan to a large segment of Southern Company system employees ranging from line management to executives. As of December 31, 2015, there were 5,405 current and former employees participating in the stock option and performance share unit programs.

Stock Options

Through 2009, stock-based compensation granted to employees consisted exclusively of non-qualified stock options. The exercise price for stock options granted equaled the stock price of Southern Company common stock on the date of grant. Stock options vest on a pro rata basis over a maximum period of three years from the date of grant or immediately upon the retirement or death of the employee. Options expire no later than 10 years after the grant date. All unvested stock options vest immediately upon a change in control where Southern Company is not the surviving corporation. Compensation expense is generally recognized on a straight-line basis over the three-year vesting period with the exception of employees that are retirement eligible at the grant date and employees that will become retirement eligible during the vesting period. Compensation expense in those instances is recognized at the grant date for employees that are retirement eligible and through the date of retirement eligibility for those employees that become retirement eligible during the vesting period. In 2015, Southern Company discontinued the granting of stock options. As a result, stock-based compensation granted to employees in 2015 consisted exclusively of performance share units.

The estimated fair values of stock options granted were derived using the Black-Scholes stock option pricing model. Expected volatility was based on historical volatility of Southern Company's stock over a period equal to the expected term. Southern Company used historical exercise data to estimate the expected term that represents the period of time that options granted to employees are expected to be outstanding. The risk-free rate was based on the U.S. Treasury yield curve in effect at the time of grant that covers the expected term of the stock options.

The following table shows the assumptions used in the pricing model and the weighted average grant-date fair value of stock options granted:

Year Ended December 31	2014	2013
Expected volatility	14.6%	16.6%
Expected term *(in years)*	5	5
Interest rate	1.5%	0.9%
Dividend yield	4.9%	4.4%
Weighted average grant-date fair value	$ 2.20	$ 2.93

Southern Company's activity in the stock option program for 2015 is summarized below:

	Shares Subject to Option	**Weighted Average Exercise Price**
Outstanding at December 31, 2014	39,929,319	$40.55
Exercised	4,032,729	36.84
Cancelled	146,684	42.31
Outstanding at December 31, 2015	**35,749,906**	**$40.96**
Exercisable at December 31, 2015	**25,857,590**	**$40.53**

The number of stock options vested, and expected to vest in the future, as of December 31, 2015 was not significantly different from the number of stock options outstanding at December 31, 2015 as stated above. As of December 31, 2015, the weighted average remaining contractual term for the options outstanding and options exercisable was approximately six years and the aggregate intrinsic value for the options outstanding and options exercisable was $209 million and $162 million, respectively.

For the years ended December 31, 2015, 2014, and 2013, total compensation cost for stock option awards recognized in income was $6 million, $27 million, and $25 million, respectively, with the related tax benefit also recognized in income of $2 million, $10 million, and $10 million, respectively. As of December 31, 2015, the total unrecognized compensation cost related to stock option awards not yet vested was immaterial.

The total intrinsic value of options exercised during the years ended December 31, 2015, 2014, and 2013 was $48 million, $125 million, and $77 million, respectively. The actual tax benefit realized by the Company for the tax deductions from stock option exercises totaled $19 million, $48 million, and $30 million for the years ended December 31, 2015, 2014, and 2013, respectively.

Southern Company has a policy of issuing shares to satisfy share option exercises. Cash received from issuances related to option exercises under the share-based payment arrangements for the years ended December 31, 2015, 2014, and 2013 was $154 million, $400 million, and $204 million, respectively.

Performance Share Units

From 2010 through 2014, stock-based compensation granted to employees included performance share units in addition to stock options. Beginning in 2015, stock-based compensation consisted exclusively of performance share units. Performance share units granted to employees vest at the end of a three-year performance period which equates to the requisite service period for accounting purposes. All unvested performance share units vest immediately upon a change in control where Southern Company is not the surviving corporation. Shares of Southern Company common stock are delivered to employees at the end of the performance period with the number of shares issued ranging from 0% to 200% of the target number of performance share units granted, based on achievement of the performance goals established by the Compensation Committee of the Southern Company Board of Directors.

The performance goal for all performance share units issued from 2010 through 2014 was based on the total shareholder return (TSR) for Southern Company common stock during the three-year performance period as compared to a group of industry peers. For these performance share units, at the end of three years, active employees receive shares based on Southern Company's performance while retired employees receive a pro rata number of shares based on the actual months of service during the performance period prior to retirement. The fair value of TSR-based performance share unit awards is determined as of the grant date using a Monte Carlo simulation model to estimate the TSR of Southern Company's common stock among the industry peers over the performance period. Southern Company recognizes compensation expense on a straight-line basis over the three-year performance period without remeasurement.

Beginning in 2015, Southern Company issued two additional types of performance share units to employees in addition to the TSR-based awards. These included performance share units with performance goals based on cumulative EPS over the performance period and performance share units with performance goals based on Southern Company's equity-weighted ROE over the performance period. The EPS-based and ROE-based awards each represent 25% of total target grant date fair value of the performance share unit awards granted. The remaining 50% of the target grant date fair value consists of TSR-based awards.

In contrast to the Monte Carlo simulation model used to determine the fair value of the TSR-based awards, the fair values of the EPS-based awards and the ROE-based awards are based on the closing stock price of Southern Company common stock on the date of the grant. Compensation expense for the EPS-based and ROE-based awards is generally recognized ratably over the three-year performance period initially assuming a 100% payout at the end of the performance period. The TSR-based performance share units, along with the EPS-based and ROE-based awards, issued in 2015, vest immediately upon the retirement of the employee. As a result, compensation expense for employees that are retirement eligible at the grant date is recognized immediately while compensation expense for employees that become retirement eligible during the vesting period is recognized over the period from grant date to the date of retirement eligibility. The expected payout related to the EPS-based and ROE-based awards is reevaluated annually with expense recognized to date increased or decreased based on the number of shares currently expected to be issued. Unlike the TSR-based awards, the compensation expense ultimately recognized for the EPS-based awards and the ROE-based awards will be based on the actual number of shares issued at the end of the performance period.

In determining the fair value of the TSR-based awards issued to employees, the expected volatility was based on the historical volatility of Southern Company's stock over a period equal to the performance period. The risk-free rate was based on the U.S. Treasury yield curve in effect at the time of grant that covers the performance period of the awards. The following table shows the assumptions used in the pricing model and the weighted average grant-date fair value of performance share award units granted:

Year Ended December 31	**2015**	2014	2013
Expected volatility	**12.9%**	12.6%	12.0%
Expected term *(in years)*	**3**	3	3
Interest rate	**1.0%**	0.6%	0.4%
Annualized dividend rate(*)	**N/A**	$ 2.03	$ 1.96
Weighted average grant-date fair value	**$ 46.38**	$ 37.54	$ 40.50

(*) Beginning in 2015, cash dividends paid on Southern Company's common stock are accumulated and payable in additional shares of Southern Company's common stock at the end of the three-year performance period and are embedded in the grant date fair value which equates to the grant date stock price.

Total unvested performance share units outstanding as of December 31, 2014 were 1,830,381. During 2015, 1,542,653 performance share units were granted, 812,740 performance share units were vested, and 79,902 performance share units were forfeited, resulting in 2,480,392 unvested performance share units outstanding at December 31, 2015. In January 2016, based on achievement of the TSR performance goal, a portion of the performance share award units granted in 2013 vested and 227,515 shares were issued at a share price of $46.80 for the three-year performance and vesting period ended December 31, 2015.

For the years ended December 31, 2015, 2014, and 2013, total compensation cost for performance share units recognized in income was $88 million, $33 million, and $31 million, respectively, with the related tax benefit also recognized in income of $34 million, $13 million, and $12 million, respectively. As of December 31, 2015, there was $33 million of total unrecognized compensation cost related to performance share award units that will be recognized over a weighted-average period of approximately 19 months.

Diluted Earnings Per Share

For Southern Company, the only difference in computing basic and diluted earnings per share 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 earnings per share were as follows:

	Average Common Stock Shares		
	2015	2014	2013
		(in millions)	
As reported shares	**910**	897	877
Effect of options and performance share award units	**4**	4	4
Diluted shares	**914**	901	881

Stock options and performance share award units that were not included in the diluted earnings per share calculation because they were anti-dilutive were 1 million and 7 million as of December 31, 2015 and 2014, respectively.

Common Stock Dividend Restrictions

The income of Southern Company is derived primarily from equity in earnings of its subsidiaries. At December 31, 2015, consolidated retained earnings included $7.0 billion of undistributed retained earnings of the subsidiaries.

9. NUCLEAR INSURANCE

Under the Price-Anderson Amendments Act (Act), Alabama Power and Georgia Power maintain agreements of indemnity with the NRC that, together with private insurance, cover third-party liability arising from any nuclear incident occurring at the companies' nuclear power plants. The Act provides funds up to $13.5 billion for public liability claims that could arise from a single nuclear incident. Each nuclear plant is insured against this liability to a maximum of $375 million by American Nuclear Insurers (ANI), with the remaining coverage provided by a mandatory program of deferred premiums that could be assessed, after a nuclear incident, against all owners of commercial nuclear reactors. A company could be assessed up to $127 million per incident for each licensed reactor it operates but not more than an aggregate of $19 million per incident to be paid in a calendar year for each reactor. Such maximum assessment, excluding any applicable state premium taxes, for Alabama Power and Georgia Power, based on its ownership and buyback interests in all licensed reactors, is $255 million and $247 million, respectively, per incident, but not more than an aggregate of $38 million and $37 million, respectively, per company to be paid for each incident in any one year. Both the maximum assessment per reactor and the maximum yearly assessment are adjusted for inflation at least every five years. The next scheduled adjustment is due no later than September 10, 2018. See Note 4 for additional information on joint ownership agreements.

Alabama Power and Georgia Power are members of Nuclear Electric Insurance Limited (NEIL), a mutual insurer established to provide property damage insurance in an amount up to $1.5 billion for members' operating nuclear generating facilities. Additionally, both companies have NEIL policies that currently provide decontamination, excess property insurance, and premature decommissioning coverage up to $1.25 billion for nuclear losses in excess of the $1.5 billion primary coverage. In April 2014, NEIL introduced a new excess non-nuclear policy providing coverage up to $750 million for non-nuclear losses in excess of the $1.5 billion primary coverage.

NEIL also covers the additional costs that would be incurred in obtaining replacement power during a prolonged accidental outage at a member's nuclear plant. Members can purchase this coverage, subject to a deductible waiting period of up to 26 weeks, with a maximum per occurrence per unit limit of $490 million. After the deductible period, weekly indemnity payments would be received until either the unit is operational or until the limit is exhausted in approximately three years. Alabama Power and Georgia Power each purchase limits based on the projected full cost of replacement power, subject to ownership limitations. Each facility has elected a 12-week deductible waiting period.

A builders' risk property insurance policy has been purchased from NEIL for the construction of Plant Vogtle Units 3 and 4. This policy provides the 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 current maximum annual assessments for Alabama Power and Georgia Power under the NEIL policies would be $55 million and $84 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 Company or to its debt trustees as may be appropriate under the policies and applicable trust indentures. In the event of a loss, the amount of insurance available might not be adequate to cover property damage and other expenses incurred. Uninsured losses and other expenses, to the extent not recovered from customers, would be borne by Alabama Power or Georgia Power, as applicable, and could have a material effect on Southern Company's financial condition and results of operations.

All retrospective assessments, whether generated for liability, property, or replacement power, may be subject to applicable state premium taxes.

10. FAIR VALUE MEASUREMENTS

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

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

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

As of December 31, 2015, assets and liabilities measured at fair value on a recurring basis during the period, together with their associated level of the fair value hierarchy, were as follows:

	Fair Value Measurements Using				
	Quoted Prices in Active Markets for Identical Assets	Significant Other Observable Inputs	Significant Unobservable Inputs	Net Asset Value as a Practical Expedient	
As of December 31, 2015:	**(Level 1)**	**(Level 2)**	**(Level 3)**	**(NAV)**	**Total**
			(in millions)		
Assets:					
Energy-related derivatives	$ —	$ 7	$ —	$ —	$ 7
Interest rate derivatives	—	22	—	—	22
Nuclear decommissioning trusts:(*)					
Domestic equity	541	69	—	—	610
Foreign equity	47	160	—	—	207
U.S. Treasury and government agency securities	—	152	—	—	152
Municipal bonds	—	64	—	—	64
Corporate bonds	11	278	—	—	289
Mortgage and asset backed securities	—	145	—	—	145
Private equity	—	—	—	17	17
Other	16	9	—	—	25
Cash equivalents	790	—	—	—	790
Other investments	9	—	1	—	10
Total	$ 1,414	$ 906	$ 1	$ 17	$ 2,338
Liabilities:					
Energy-related derivatives	$ —	$ 220	$ —	$ —	$ 220
Interest rate derivatives	—	30	—	—	30
Total	$ —	$ 250	$ —	$ —	$ 250

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

As of December 31, 2014, assets and liabilities measured at fair value on a recurring basis during the period, together with their associated level of the fair value hierarchy, were as follows:

	Fair Value Measurements Using				
	Quoted Prices in Active Markets for Identical Assets	Significant Other Observable Inputs	Significant Unobservable Inputs	Net Asset Value as a Practical Expedient	
As of December 31, 2014:	**(Level 1)**	**(Level 2)**	**(Level 3)**	**(NAV)**	**Total**
			(in millions)		
Assets:					
Energy-related derivatives	$ —	$ 13	$ —	$ —	$ 13
Interest rate derivatives	—	8	—	—	8
Nuclear decommissioning trusts:(*)					
Domestic equity	583	85	—	—	668
Foreign equity	34	184	—	—	218
U.S. Treasury and government agency securities	—	130	—	—	130
Municipal bonds	—	62	—	—	62
Corporate bonds	—	299	—	—	299
Mortgage and asset backed securities	—	139	—	—	139
Private equity	—	—	—	3	3
Other	11	13	—	—	24
Cash equivalents	397	—	—	—	397
Other investments	9	—	1	—	10
Total	$ 1,034	$ 933	$ 1	$ 3	$ 1,971
Liabilities:					
Energy-related derivatives	$ —	$ 201	$ —	$ —	$ 201
Interest rate derivatives	—	24	—	—	24
Total	$ —	$ 225	$ —	$ —	$ 225

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

Valuation Methodologies

The energy-related derivatives primarily consist of over-the-counter financial products for natural gas and physical power products, including, from time to time, basis swaps. These are standard products used within the energy industry and are valued using the market approach. The inputs used are mainly from observable market sources, such as forward natural gas prices, power prices, implied volatility, and overnight index swap interest rates. Interest rate derivatives are also standard over-the-counter products that are valued using observable market data and assumptions commonly used by market participants. The fair value of interest rate derivatives reflect the net present value of expected payments and receipts under the swap agreement based on the market's expectation of future interest rates. Additional inputs to the net present value calculation may include the contract terms, counterparty credit risk and occasionally, implied volatility of interest rate options. The interest rate derivatives are categorized as Level 2 under Fair Value Measurements as these inputs are based on observable data and valuations of similar instruments. See Note 11 for additional information on how these derivatives are used.

The NRC requires licensees of commissioned nuclear power reactors to establish a plan for providing reasonable assurance of funds for future decommissioning. For fair value measurements of the investments within the nuclear decommissioning trusts, external pricing vendors are designated for each asset class with each security specifically assigned a primary pricing source. For investments held within commingled funds, fair value is determined at the end of each business day through the net asset value, which is established by obtaining the underlying securities' individual prices from the primary pricing source. A market price secured from the primary source vendor is then evaluated by management in its valuation of the assets within the trusts. As a general approach, fixed income market pricing vendors gather market data (including indices and market research reports) and integrate relative credit information, observed market movements, and sector news into proprietary pricing models, pricing systems, and mathematical tools. Dealer quotes and other market information, including live trading levels and pricing analysts' judgments, are also obtained when available. See Note 1 under "Nuclear Decommissioning" for additional information.

"Other investments" include investments that are not traded in the open market. The fair value of these investments have been determined based on market factors including comparable multiples and the expectations regarding cash flows and business plan executions.

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

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

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

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

As of December 31, 2015 and 2014, other financial instruments for which the carrying amount did not equal fair value were as follows:

	Carrying Amount	Fair Value
	(in millions)	
Long-term debt, including securities due within one year:		
2015	**$ 27,216**	**$ 27,913**
2014	$ 23,814	$ 25,816

The fair values are determined using Level 2 measurements and are based on quoted market prices for the same or similar issues or on the current rates available to Southern Company, Alabama Power, Georgia Power, Gulf Power, Mississippi Power, and Southern Power.

11. DERIVATIVES

Southern Company, the traditional operating companies, and Southern Power are exposed to market risks, primarily commodity price risk and interest rate risk. To manage the volatility attributable to these exposures, each company nets its exposures, where possible, to take advantage of natural offsets and enters into various derivative transactions for the remaining exposures pursuant to each company's policies in areas such as counterparty exposure and risk management practices. Each company's policy is that derivatives are to be used primarily for hedging purposes and mandates strict adherence to all applicable risk management policies. Derivative positions are monitored using techniques including, but not limited to, market valuation, value at risk, stress testing, and sensitivity analysis. Derivative instruments are recognized at fair value in the balance sheets as either assets or liabilities and are presented on a gross basis. See Note 10 for additional information. In the statements of cash flows, the cash impacts of settled energy-related and interest rate derivatives are recorded as operating activities.

Energy-Related Derivatives

The traditional operating companies and Southern Power enter into energy-related derivatives to hedge exposures to electricity, gas, and other fuel price changes. However, due to cost-based rate regulations and other various cost recovery mechanisms, the traditional operating companies have limited exposure to market volatility in commodity fuel prices and prices of electricity. Each of the traditional operating companies manages fuel-hedging programs, implemented per the guidelines of their respective state PSCs, through the use of financial derivative contracts, which is expected to continue to mitigate price volatility. The traditional operating companies (with respect to wholesale generating capacity) and Southern Power have limited exposure to market volatility in commodity fuel prices and prices of electricity because their long-term sales contracts shift substantially all fuel cost responsibility to the purchaser. However, the traditional operating companies and Southern Power may be exposed to market volatility in energy-related commodity prices to the extent any uncontracted wholesale generating capacity is used to sell electricity.

Energy-related derivative contracts are accounted for under one of three methods:

- *Regulatory Hedges* – Energy-related derivative contracts which are designated as regulatory hedges relate primarily to the traditional operating companies' fuel-hedging programs, where gains and losses are initially recorded as regulatory liabilities and assets, respectively, and then are included in fuel expense as the underlying fuel is used in operations and ultimately recovered through the respective fuel cost recovery clauses.
- *Cash Flow Hedges* – Gains and losses on energy-related derivatives designated as cash flow hedges (which are mainly used to hedge anticipated purchases and sales) are initially deferred in OCI before being recognized in the statements of income in the same period as the hedged transactions are reflected in earnings.
- *Not Designated* – Gains and losses on energy-related derivative contracts that are not designated or fail to qualify as hedges are recognized in the statements of income as incurred.

Some energy-related derivative contracts require physical delivery as opposed to financial settlement, and this type of derivative is both common and prevalent within the electric industry. When an energy-related derivative contract is settled physically, any cumulative unrealized gain or loss is reversed and the contract price is recognized in the respective line item representing the actual price of the underlying goods being delivered.

At December 31, 2015, the net volume of energy-related derivative contracts for natural gas positions totaled 224 million mmBtu for the Southern Company system, with the longest hedge date of 2020 over which the respective entity is hedging its exposure to the variability in future cash flows for forecasted transactions and the longest non-hedge date of 2017 for derivatives not designated as hedges.

In addition to the volumes discussed above, the traditional operating companies and Southern Power enter into physical natural gas supply contracts that provide the option to sell back excess gas due to operational constraints. The maximum expected volume of natural gas subject to such a feature is 5 million mmBtu.

For cash flow hedges, the amounts expected to be reclassified from accumulated OCI to earnings for the next 12-month period ending December 31, 2016 are immaterial for Southern Company.

Interest Rate Derivatives

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

At December 31, 2015, 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, 2015
	(in millions)				*(in millions)*
Cash Flow Hedges of Forecasted Debt					
	$ 1,000	3-month LIBOR	2.37%	November 2026	$ 1
	1,000	3-month LIBOR	2.70%	November 2046	(1)
	200	3-month LIBOR	2.93%	October 2025	(15)
	80	3-month LIBOR	2.32%	December 2026	1
Cash Flow Hedges of Existing Debt					
	250	3-month LIBOR + 0.32%	0.75%	March 2016	—
	200	3-month LIBOR + 0.40%	1.01%	August 2016	—
Fair Value Hedges of Existing Debt					
	250	1.30%	3-month LIBOR + 0.17%	August 2017	1
	300	2.75%	3-month LIBOR + 0.92%	June 2020	2
	250	5.40%	3-month LIBOR + 4.02%	June 2018	1
	200	4.25%	3-month LIBOR + 2.46%	December 2019	2
	500	1.95%	3-month LIBOR + 0.76%	December 2018	(3)
Derivatives not Designated as Hedges					
	65[a,d]	3-month LIBOR	2.50%	October 2016[e]	1
	47[b,d]	3-month LIBOR	2.21%	October 2016[e]	1
	65[c,d]	3-month LIBOR	2.21%	November 2016[f]	1
Total	$ 4,407				$ (8)

(a) Swaption at RE Tranquillity LLC. See Note 12 for additional information.
(b) Swaption at RE Roserock LLC. See Note 12 for additional information.
(c) Swaption at RE Garland Holdings LLC. See Note 12 for additional information.
(d) Amortizing notional amount.
(e) Represents the mandatory settlement date. Settlement amount will be based on a 15-year amortizing swap.
(f) Represents the mandatory settlement date. Settlement amount will be based on a 12-year amortizing swap.

The estimated pre-tax gains (losses) that will be reclassified from accumulated OCI to interest expense for the next 12-month period ending December 31, 2016 are immaterial. The Company has deferred gains and losses that are expected to be amortized into earnings through 2046.

Derivative Financial Statement Presentation and Amounts

At December 31, 2015 and 2014, the fair value of energy-related derivatives and interest rate derivatives was reflected in the balance sheets as follows:

	Asset Derivatives			Liability Derivatives		
Derivative Category	**Balance Sheet Location**	**2015**	2014	**Balance Sheet Location**	**2015**	2014
		(in millions)			*(in millions)*	
Derivatives designated as hedging instruments for regulatory purposes						
Energy-related derivatives:	Other current assets	**$ 3**	$ 7	Liabilities from risk management activities	**$ 130**	$ 118
	Other deferred charges and assets	**—**	—	Other deferred credits and liabilities	**87**	79
Total derivatives designated as hedging instruments for regulatory purposes		**$ 3**	$ 7		**$ 217**	$ 197
Derivatives designated as hedging instruments in cash flow and fair value hedges						
Energy-related derivatives:	Other current assets	**$ 3**	$ —	Liabilities from risk management activities	**$ 2**	$ —
Interest rate derivatives:	Other current assets	**19**	7	Liabilities from risk management activities	**23**	17
	Other deferred charges and assets	**—**	1	Other deferred credits and liabilities	**7**	7
Total derivatives designated as hedging instruments in cash flow and fair value hedges		**$ 22**	$ 8		**$ 32**	$ 24
Derivatives not designated as hedging instruments						
Energy-related derivatives:	Other current assets	**$ 1**	$ 6	Liabilities from risk management activities	**$ 1**	$ 4
Interest rate derivatives:	Other current assets	**3**	—	Liabilities from risk management activities	**—**	—
Total derivatives not designated as hedging instruments		**$ 4**	$ 6		**$ 1**	$ 4
Total		**$ 29**	$ 21		**$ 250**	$ 225

The Company's derivative contracts are not subject to master netting arrangements or similar agreements and are reported gross on the Company's financial statements. Some of these energy-related and interest rate derivative contracts 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. Amounts related to energy-related derivative contracts and interest rate derivative contracts at December 31, 2015 and 2014 are presented in the following tables.

	Fair Value				
Assets	**2015**	2014	**Liabilities**	**2015**	2014
	(in millions)			*(in millions)*	
Energy-related derivatives presented in the Balance Sheet[a]	**$ 7**	$ 13	Energy-related derivatives presented in the Balance Sheet[a]	**$ 220**	$ 201
Gross amounts not offset in the Balance Sheet[b]	**(6)**	(9)	Gross amounts not offset in the Balance Sheet[b]	**(6)**	(9)
Net energy-related derivative assets	**$ 1**	$ 4	**Net energy-related derivative liabilities**	**$ 214**	$ 192
Interest rate derivatives presented in the Balance Sheet[a]	**$ 22**	$ 8	Interest rate derivatives presented in the Balance Sheet[a]	**$ 30**	$ 24
Gross amounts not offset in the Balance Sheet[b]	**(9)**	(8)	Gross amounts not offset in the Balance Sheet[b]	**(9)**	(8)
Net interest rate derivative assets	**$ 13**	$ —	**Net interest rate derivative liabilities**	**$ 21**	$ 16

(a) The Company does not offset fair value amounts for multiple derivative instruments executed with the same counterparty on the balance sheets; therefore, gross and net amounts of derivative assets and liabilities presented on the balance sheets are the same.
(b) Includes gross amounts subject to netting terms that are not offset on the balance sheets and any cash/financial collateral pledged or received.

At December 31, 2015 and 2014, the pre-tax effects of unrealized derivative gains (losses) arising from energy-related derivative instruments designated as regulatory hedging instruments and deferred were as follows:

	Unrealized Losses			Unrealized Gains		
Derivative Category	**Balance Sheet Location**	**2015**	2014	**Balance Sheet Location**	**2015**	2014
		(in millions)			*(in millions)*	
Energy-related derivatives:	Other regulatory assets, current	**$ (130)**	$ (118)	Other regulatory liabilities, current	**$ 3**	$ 7
	Other regulatory assets, deferred	**(87)**	(79)	Other regulatory liabilities, deferred	**—**	—
Total energy-related derivative gains (losses)		**$ (217)**	$ (197)		**$ 3**	$ 7

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

Derivatives in Cash Flow Hedging Relationships	**Gain (Loss) Recognized in OCI on Derivative (Effective Portion)**			**Gain (Loss) Reclassified from Accumulated OCI into Income (Effective Portion)**			
					Amount		
Derivative Category	**2015**	2014	2013	**Statements of Income Location**	**2015**	2014	2013
		(in millions)				*(in millions)*	
Interest rate derivatives	**$ (22)**	$ (16)	$ —	Interest expense, net of amounts capitalized	**$ (9)**	$ (8)	$ (14)

For the years ended December 31, 2015, 2014, and 2013, the pre-tax effects of energy-related derivatives designated as cash flow hedging instruments recognized in OCI and those reclassified from OCI into earnings were immaterial for Southern Company.

For the years ended December 31, 2015, 2014, and 2013, the pre-tax effects of interest rate derivatives designated as fair value hedging instruments were immaterial and offset by changes to the carrying value of long-term debt.

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

For the years ended December 31, 2015, 2014, and 2013, the pre-tax effects of energy-related and interest rate derivatives not designated as hedging instruments on the statements of income were immaterial for Southern Company.

Contingent Features

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

At December 31, 2015, the fair value of derivative liabilities with contingent features was $52 million. The maximum potential collateral requirements arising from the credit-risk-related contingent features, at a rating below BBB- and/or Baa3, were $52 million and include certain agreements that could require collateral in the event that one or more Southern Company system power pool participants has a credit rating change to below investment grade.

Generally, collateral may be provided by a Southern Company guaranty, letter of credit, or cash. If collateral is required, fair value amounts recognized for the right to reclaim cash collateral or the obligation to return cash collateral are not offset against fair value amounts recognized for derivatives executed with the same counterparty.

Southern Company, the traditional operating companies, and Southern Power are exposed to losses related to financial instruments in the event of counterparties' nonperformance. Southern Company, the traditional operating companies, and Southern Power 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. Southern Company, the traditional operating companies, and Southern Power have also established risk management policies and controls to determine and monitor the creditworthiness of counterparties in order to mitigate Southern Company's, the traditional operating companies', and Southern Power's exposure to counterparty credit risk. Therefore, Southern Company, the traditional operating companies, and Southern Power do not anticipate a material adverse effect on the financial statements as a result of counterparty nonperformance.

12. ACQUISITIONS

Southern Company

Proposed Merger with AGL Resources

On August 23, 2015, Southern Company entered into the Merger Agreement to acquire AGL Resources. Under the terms of the Merger Agreement, subject to the satisfaction or waiver (if permissible under applicable law) of specified conditions, Merger Sub will be merged with and into AGL Resources. AGL Resources will survive the Merger and become a wholly-owned, direct subsidiary of Southern Company. Upon the consummation of the Merger, each share of common stock of AGL Resources issued and outstanding immediately prior to the effective time of the Merger (Effective Time), other than shares owned by AGL Resources as treasury stock, shares owned by a subsidiary of AGL Resources, and any shares owned by shareholders who have properly exercised and perfected dissenters' rights, will be converted into the right to receive $66 in cash, without interest and less any applicable withholding taxes (Merger Consideration). Other equity-based securities of AGL Resources will be cancelled for cash consideration or converted into new awards from Southern Company as described in the Merger Agreement.

In accordance with GAAP, the Merger will be accounted for using the acquisition method of accounting whereby the assets acquired and liabilities assumed are recognized at fair value as of the acquisition date. The excess of the purchase price over the fair values of AGL Resources' assets and liabilities will be recorded as goodwill. Southern Company expects total cash of $8.2 billion to be required to fund the purchase price of approximately $8.0 billion to acquire AGL Resources common stock, options to purchase shares of AGL Resources common stock, and restricted stock units payable in shares of AGL Resources common stock and to fund acquisition-related expenses and financing costs of approximately $200 million. Southern Company will also assume AGL Resources' outstanding indebtedness.

The Merger was approved by AGL Resources' shareholders on November 19, 2015, and the waiting period under the Hart-Scott-Rodino Antitrust Improvements Act of 1976 expired on December 4, 2015. Consummation of the Merger remains subject to the satisfaction or waiver of certain closing conditions, including, among others, (i) the approval of the California Public Utilities Commission, Georgia PSC, Illinois Commerce Commission, Maryland PSC, and New Jersey Board of Public Utilities, and other approvals required under applicable state laws, and the approval of the Federal Communications Commission (FCC) for the transfer of control over the FCC licenses of certain subsidiaries of AGL Resources, (ii) the absence of a judgment, order, decision, injunction, ruling, or other finding or agency requirement of a governmental entity prohibiting the consummation of the Merger, and (iii) other customary closing conditions, including (a) subject to certain materiality qualifiers, the accuracy of each party's representations and warranties and (b) each party's performance in all material respects of its obligations under the Merger Agreement. Southern Company completed the required state regulatory applications in the fourth quarter 2015 and the required FCC filings in February 2016. On February 24, 2016, a stipulation and settlement agreement between Southern Company, AGL Resources, the Maryland PSC Staff, and the Maryland Office of People's Counsel was filed with the Maryland PSC. The proposed settlement remains subject to the approval of the Maryland PSC. Additionally, Southern Company received the approval of the Virginia State Corporation Commission in February 2016.

Subject to certain limitations, either party may terminate the Merger Agreement if the Merger is not consummated by August 23, 2016, which date may be extended by either party to February 23, 2017 if, on August 23, 2016, all conditions to closing other than those relating to (i) regulatory approvals and (ii) the absence of legal restraints preventing consummation of the Merger (to the extent relating to regulatory approvals) have been satisfied. Upon termination of the Merger Agreement under certain specified circumstances, AGL Resources will be required to pay Southern Company a termination fee of $201 million or reimburse Southern Company's expenses up to $5 million (which reimbursement shall reduce on a dollar-for-dollar basis any termination fee subsequently payable by AGL Resources). Southern Company currently expects to complete the transaction in the second half of 2016.

During 2015, the Company incurred external transaction costs for financing, legal, and consulting services associated with the proposed Merger of approximately $41 million.

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

Merger Financing

Southern Company intends to initially fund the cash consideration for the Merger using a mix of debt and equity. Southern Company expects to issue the debt to fund the Merger Consideration in several tranches including long-dated maturities. The amount of debt issued at each maturity will depend on prevailing market conditions at the time of the offering and other factors. In addition, Southern Company entered into the $8.1 billion Bridge Agreement on September 30, 2015 to provide financing for the Merger in the event long-term financing is not available. See Note 6 under "Bank Credit Arrangements" for additional information regarding the Bridge Agreement.

Proposed Acquisition of PowerSecure International, Inc. (Unaudited)

On February 24, 2016, Southern Company entered into an Agreement and Plan of Merger to acquire PowerSecure International, Inc. Under the terms of this merger agreement, the stockholders of PowerSecure International, Inc. will be entitled to receive $18.75 in cash for each share of common stock in a transaction with a total purchase price of approximately $431 million. Following this transaction, PowerSecure International, Inc. will become a wholly-owned subsidiary of Southern Company. This transaction is expected to close by the end of the second quarter 2016, subject to, among other items, approval by PowerSecure International, Inc. stockholders and notification, clearance, and reporting requirements under the Hart-Scott-Rodino Antitrust Improvements Act of 1976.

Southern Power

During 2015 and 2014, in accordance with Southern Power's overall growth strategy, Southern Power acquired or contracted to acquire through its wholly-owned subsidiaries, Southern Renewable Partnerships, LLC or Southern Renewable Energy, Inc. (SRE), the projects set forth in the following table. Acquisition-related costs of approximately $4 million were expensed as incurred. The acquisitions do not include any contingent consideration unless specifically noted.

2015

Project Facility	Seller; Acquisition Date	Approx. Nameplate Capacity	Location	Southern Power Percentage Ownership	Expected/ Actual COD	PPA Counterparties for Plant Output	PPA Contract Period	Approx. Purchase Price
		(MW)						*(in millions)*
WIND								
Kay Wind	Apex Clean Energy Holdings, LLC December 11, 2015	299	Kay County, OK	100%	December 12, 2015	Westar Energy, Inc. and Grant River Dam Authority	20 years	$ 481[(b)]
Grant Wind	Apex Clean Energy Holdings, LLC	151	Grant County, OK	100%	March 2016	Western Farmers, East Texas, and Northeast Texas Electric Cooperative	20 years	$ 258[(c)]
SOLAR								
Lost Hills Blackwell	First Solar, Inc. (First Solar) April 15, 2015	33	Kern County, CA	51% [(a)]	April 17, 2015	City of Roseville, California/Pacific Gas and Electric Company	29 years	$ 73[(d)]
North Star	First Solar April 30, 2015	61	Fresno County, CA	51% [(a)]	June 20, 2015	Pacific Gas and Electric Company	20 years	$ 208[(e)]
Tranquillity	Recurrent Energy, LLC August 28, 2015	205	Fresno County, CA	51% [(a)]	Fourth quarter 2016	Shell Energy North America (US), LP and then Southern California Edison (SCE)	18 years	$ 100[(f)]
Desert Stateline	First Solar August 31, 2015	299	San Bernardino County, CA	51% [(a)]	From December 2015 to third quarter 2016 [(h)]	SCE	20 years	$ 439[(g)]
Morelos	Solar Frontier Americas Holding, LLC October 22, 2015	15	Kern County, CA	90%	November 25, 2015	Pacific Gas and Electric Company	20 years	$ 45[(i)]
Roserock	Recurrent Energy, LLC November 23, 2015	160	Pecos County, TX	51% [(a)]	Fourth quarter 2016	Austin Energy	20 years	$ 45[(j)]
Garland and Garland A	Recurrent Energy, LLC December 17, 2015	205	Kern County, CA	51% [(a)]	Fourth quarter 2016	SCE	15 years and 20 years	$ 49[(k)]
Calipatria	Solar Frontier Americas Holding, LLC February 11, 2016	20	Imperial County, CA	90%	February 11, 2016	San Diego Gas & Electric Company	20 years	$ 52[(l)]

(a) Southern Power owns 100% of the class A membership interests and a wholly-owned subsidiary of the seller owns 100% of the class B membership interests. Southern Power and the class B member are entitled to 51% and 49%, respectively, of all cash distributions from the project. In addition, Southern Power is entitled to substantially all of the federal tax benefits with respect to the transaction. At each acquisition, Southern Power acquired a controlling interest in the entity owning the project facility and recorded approximately $227 million for the noncontrolling interests, in the aggregate, which is recorded as a non-cash transaction in contributions from noncontrolling interests and plant acquisitions.

(b) ***Kay Wind*** - The total purchase price, including $35 million of contingent consideration, is approximately $481 million. As of December 31, 2015, the fair values of the assets and liabilities acquired through the business combination were recorded as follows: $481 million as CWIP, $8 million as a receivable related to transmission interconnection costs, and $8 million as payables; however, the allocation of the purchase price to individual assets has not been finalized.

(c) ***Grant Wind*** - On September 4, 2015, Southern Power entered into an agreement to acquire Grant Wind, LLC. The completion of the acquisition is subject to the seller achieving certain construction and project milestones as well as various other customary conditions to closing. The acquisition is expected to close at or near the expected COD. The purchase price includes approximately $24 million of contingent consideration and may be adjusted based on performance testing and production over the first 10 years of operation. The ultimate outcome of this matter cannot be determined at this time.

(d) ***Lost Hills Blackwell*** - Concurrent with the acquisition, a wholly-owned subsidiary of First Solar acquired 100% of the class B membership interests for approximately $34 million. At the acquisition date, the members became contingently obligated to pay $3 million of construction payables through COD, making the aggregate purchase price approximately $107 million. The fair values of the assets acquired through the business combination were recorded as follows: $105 million as property, plant, and equipment, $3 million as a receivable related to transmission interconnection costs, and $4 million as construction and other payables; however, the allocation of the purchase price to individual assets has not been finalized.

(e) ***North Star*** - Concurrent with the acquisition, a wholly-owned subsidiary of First Solar acquired 100% of the class B membership interests for approximately $99 million. At the acquisition date, the members became contingently obligated to pay $233 million of construction payables through COD, making the aggregate purchase price approximately $307 million. The fair values of the assets acquired through the business combination were recorded as follows: $266 million as property, plant, and equipment, $25 million as an intangible asset, $21 million as a receivable related to transmission interconnection costs, and $238 million as construction and other payables; however, the allocation of the purchase price to individual assets has not been finalized. The intangible asset consists of an acquired PPA that will be amortized over its 20-year term. The amortization expense for the year ended December 31, 2015 was $1 million. The estimated amortization for future periods is approximately $1.2 million per year for 2016 through 2020, and $18 million thereafter.

(f) ***Tranquillity*** - Concurrent with the acquisition, a wholly-owned subsidiary of Recurrent Energy, LLC converted all its membership interests to 100% of the class B membership interests after contributing approximately $173 million of assets and receiving an initial distribution of $100 million. As of December 31, 2015, the fair values of the assets and liabilities acquired through the business combination were recorded as follows: $186 million as CWIP, $24 million as other receivables, and $37 million as payables; however, the allocation of the purchase price to individual assets has not been finalized. Total construction costs, which include the acquisition price allocated to CWIP, are expected to be approximately $473 million to $493 million. The ultimate outcome of this matter cannot be determined at this time.

(g) ***Desert Stateline*** - Concurrent with the acquisition, a wholly-owned subsidiary of First Solar acquired 100% of the class B membership interests for approximately $223 million. As of December 31, 2015, the fair values of the assets acquired through the business combination, which includes Southern Power's and First Solar's initial payments due under the related construction agreement, were recorded as follows: $413 million as CWIP and $249 million as an intangible asset; however, the allocation of the purchase price to individual assets has not been finalized. The intangible asset consists of an acquired PPA that will be amortized over its 20-year term. The estimated amortization for future periods is approximately $6.2 million in 2016, $12.5 million per year for 2017 through 2020, and $192.8 million thereafter. Total construction costs, which include the acquisition price allocated to CWIP, are expected to be approximately $1.2 billion to $1.3 billion. The ultimate outcome of this matter cannot be determined at this time.

(h) ***Desert Stateline*** - The first three of eight phases were placed in service in December 2015. Subsequent to December 31, 2015, phases four and five were placed in service.

(i) ***Morelos*** - The total purchase price, including the minority owner, Turner Renewable Energy, LLC's (TRE) 10% ownership interest, is approximately $50 million. As of December 31, 2015, the fair values of the assets acquired through the business combination were recorded as follows: $49 million as property, plant, and equipment and $1 million as a receivable related to transmission interconnection costs; however, the allocation of the purchase price to individual assets has not been finalized.

(j) ***Roserock*** - Concurrent with the acquisition, a wholly-owned subsidiary of Recurrent Energy, LLC converted all its membership interests to 100% of the class B membership interests after contributing approximately $26 million of assets. As of December 31, 2015, the fair values of the assets and liabilities acquired through the business combination were recorded as follows: $75 million as CWIP, $6 million as other receivables, and $10 million as payables and accrued expenses; however, the allocation of the purchase price to individual assets has not been finalized. Total construction costs, which include the acquisition price allocated to CWIP, are expected to be approximately $333 million to $353 million. The ultimate outcome of this matter cannot be determined at this time.

(k) ***Garland and Garland A*** - Concurrent with the acquisition, a wholly-owned subsidiary of Recurrent Energy, LLC converted all its membership interests to 100% of the class B membership interests after contributing approximately $31 million of assets. As of December 31, 2015, the fair values of the assets and liabilities acquired through the business combination were recorded as follows: $107 million as CWIP, $1 million as other deferred assets, and $28 million as payables and other accrued expenses; however, the allocation of the purchase price to individual assets has not been finalized. Total construction costs, which include the acquisition price allocated to CWIP, are expected to be approximately $532 million to $552 million. The ultimate outcome of this matter cannot be determined at this time.

(l) ***Calipatria*** - The total purchase price, including the minority owner, TRE's 10% ownership interest, is approximately $58 million.

2014

Project Facility	Seller; Acquisition Date	Approx. Nameplate Capacity	Location	Southern Power Percentage Ownership	COD	PPA Counterparties for Plant Output	PPA Contract Period	Approx. Purchase Price
		(MW)						*(in millions)*
SOLAR								
Adobe	Sun Edison, LLC April 17, 2014	20	Kern County, CA	90%	May 21, 2014	SCE	20 years	$ 86[(b)]
Macho Springs	First Solar Development, LLC May 22, 2014	50	Luna County, NM	90%	May 23, 2014	El Paso Electric Company	20 years	$ 117[(c)]
Imperial Valley	First Solar, October 22, 2014	150	Imperial County, CA	51% [(a)]	November 26, 2014	San Diego Gas & Electric Company	25 years	$ 505[(d)]

(a) Southern Power owns 100% of the class A membership interests and a wholly-owned subsidiary of the seller owns 100% of the class B membership interests. Southern Power and the class B member are entitled to 51% and 49%, respectively, of all cash distributions from the project. In addition, Southern Power is entitled to substantially all of the federal tax benefits with respect to the transaction.

(b) ***Adobe*** - Total purchase price, including the minority owner TRE's 10% ownership interest, was $97 million. The fair values of the assets acquired were ultimately recorded as follows: $84 million to property, plant, and equipment, $15 million to prepayment related to transmission services, and $6 million to PPA intangible, resulting in a $5 million bargain purchase gain and a $3 million deferred tax liability. The bargain purchase gain is included in other income (expense), net. Acquisition-related costs were expensed as incurred and were not material.

(c) ***Macho Springs*** - Total purchase price, including the minority owner TRE's 10% ownership interest, was $130 million. The fair values of the assets acquired were ultimately recorded as follows: $128 million to property, plant, and equipment, $1 million to prepaid property taxes, and $1 million to prepayment related to transmission services. The acquisition did not include any contingent consideration. Acquisition-related costs were expensed as incurred and were not material.

(d) ***Imperial Valley*** - In connection with this acquisition, SG2 Holdings, LLC (SG2 Holdings) made an aggregate payment of approximately $128 million to a subsidiary of First Solar and became obligated to pay additional contingent consideration of approximately $599 million upon completion of the facility (representing the amount due to an affiliate of First Solar under the construction contract for Imperial Valley). When substantial completion was achieved in November 2014, a subsidiary of First Solar was admitted as a minority member of SG2 Holdings. The members of SG2 Holdings made additional agreed upon capital contributions totaling $593 million to SG2 Holdings that were used to pay the contingent consideration due, leaving $6.0 million of contingent consideration payable upon final acceptance of the facility. As a result of these capital contributions, the aggregate purchase price payable by Southern Power for the acquisition of Imperial Valley was approximately $505 million in addition to the $223 million noncash contribution by the minority member. The fair values of the assets acquired were ultimately recorded as follows: $708 million to property, plant, and equipment and $20 million to prepayment related to transmission services. Acquisition-related costs were expensed as incurred and were not material.

Construction Projects

During 2015, in accordance with Southern Power's overall growth strategy, Southern Power constructed or commenced construction of the projects set forth in the table below, in addition to the Tranquillity, Desert Stateline, Roserock, Garland, and Garland A facilities. Total cost of construction incurred for these projects during 2015 was $1.8 billion, of which $1.1 billion remains in CWIP at December 31, 2015.

Solar Facility	Seller	Approx. Nameplate Capacity	County Location in Georgia	Expected/ Actual COD	PPA Counterparties for Plant Output	PPA Contract Period	Estimated Construction Cost
		(MW)					*(in millions)*
Sandhills	N/A	146	Taylor	Fourth quarter 2016	Cobb, Flint, and Sawnee Electric Membership Corporations	25 years	$ 260 - 280
Decatur Parkway	TradeWind Energy, Inc.	84	Decatur	December 31, 2015	Georgia Power[a]	25 years	Approx. $169[c]
Decatur County	TradeWind Energy, Inc.	20	Decatur	December 29, 2015	Georgia Power	20 years	Approx. $46[c]
Butler	CERSM, LLC and Community Energy, Inc.	103	Taylor	Fourth quarter 2016	Georgia Power[b]	30 years	$ 220 - 230[c]
Pawpaw	Longview Solar, LLC	30	Taylor	March 2016	Georgia Power[a]	30 years	$ 70 - 80[c]
Butler Solar Farm	Strata Solar Development, LLC	22	Taylor	February 10, 2016	Georgia Power	20 years	Approx. $45[c]

(a) Affiliate PPA approved by the FERC.
(b) Affiliate PPA subject to FERC approval.
(c) Includes the acquisition price of all outstanding membership interests of the respective development entity.

13. SEGMENT AND RELATED INFORMATION

The primary business of the Southern Company system is electricity sales by the traditional operating companies and Southern Power. The four traditional operating companies – Alabama Power, Georgia Power, Gulf Power and Mississippi Power – are vertically integrated utilities providing electric service in four Southeastern states. Southern Power constructs, acquires, owns, and manages generation assets, including renewable energy projects, and sells electricity at market-based rates in the wholesale market.

Southern Company's reportable business segments are the sale of electricity by the four traditional operating companies and Southern Power. Revenues from sales by Southern Power to the traditional operating companies were $417 million, $383 million, and $346 million in 2015, 2014, and 2013, respectively. The "All Other" column includes parent Southern Company, which does not allocate operating expenses to business segments. Also, this category includes segments below the quantitative threshold for separate disclosure. These segments include investments in telecommunications and leveraged lease projects. All other inter-segment revenues are not material. Financial data for business segments and products and services for the years ended December 31, 2015, 2014, and 2013 was as follows:

	Electric Utilities						
	Traditional Operating Companies	Southern Power	Eliminations	Total	All Other	Eliminations	Consolidated
				(in millions)			
2015							
Operating revenues	**$ 16,491**	**$ 1,390**	**$ (439)**	**$ 17,442**	**$ 152**	**$ (105)**	**$ 17,489**
Depreciation and amortization	**1,772**	**248**	**—**	**2,020**	**14**	**—**	**2,034**
Interest income	**19**	**2**	**1**	**22**	**6**	**(5)**	**23**
Interest expense	**697**	**77**	**—**	**774**	**69**	**(3)**	**840**
Income taxes	**1,305**	**21**	**—**	**1,326**	**(132)**	**—**	**1,194**
Segment net income (loss)[(a) (b)]	**2,186**	**215**	**—**	**2,401**	**(32)**	**(2)**	**2,367**
Total assets	**69,052**	**8,905**	**(397)**	**77,560**	**1,819**	**(1,061)**	**78,318**
Gross property additions	**5,124**	**1,005**	**—**	**6,129**	**40**	**—**	**6,169**
2014							
Operating revenues	$ 17,354	$ 1,501	$ (449)	$ 18,406	$ 159	$ (98)	$ 18,467
Depreciation and amortization	1,709	220	—	1,929	16	—	1,945
Interest income	17	1	—	18	3	(2)	19
Interest expense	705	89	—	794	43	(2)	835
Income taxes	1,056	(3)	—	1,053	(76)	—	977
Segment net income (loss)[(a) (b)]	1,797	172	—	1,969	(3)	(3)	1,963
Total assets[(c)]	64,300	5,233	(131)	69,402	1,143	(312)	70,233
Gross property additions	5,568	942	—	6,510	11	1	6,522
2013							
Operating revenues	$ 16,136	$ 1,275	$ (376)	$ 17,035	$ 139	$ (87)	$ 17,087
Depreciation and amortization	1,711	175	—	1,886	15	—	1,901
Interest income	17	1	—	18	2	(1)	19
Interest expense	714	74	—	788	36	—	824
Income taxes	889	46	—	935	(85)	(1)	849
Segment net income (loss)[(a) (b)]	1,486	166	—	1,652	(10)	2	1,644
Total assets[(c)]	59,188	4,417	(101)	63,504	1,064	(304)	64,264
Gross property additions	5,226	633	—	5,859	9	—	5,868

(a) Attributable to Southern Company.
(b) Segment net income (loss) for the traditional operating companies includes pre-tax charges for estimated probable losses on the Kemper IGCC of $365 million ($226 million after tax) in 2015, $868 million ($536 million after tax) in 2014, and $1.2 billion ($729 million after tax) in 2013. See Note 3 under "Integrated Coal Gasification Combined Cycle – Kemper IGCC Schedule and Cost Estimate" for additional information.
(c) Net of $202 million and $139 million of unamortized debt issuance costs as of December 31, 2014 and 2013, respectively. Also net of $488 million and $143 million of deferred tax assets as of December 31, 2014 and 2013, respectively. See Note 1 under "Recently Issued Accounting Standards" for additional information.

Products and Services

	Electric Utilities' Revenues			
Year	Retail	Wholesale	Other	Total
		(in millions)		
2015	**$ 14,987**	**$ 1,798**	**$ 657**	**$ 17,442**
2014	15,550	2,184	672	18,406
2013	14,541	1,855	639	17,035

14. QUARTERLY FINANCIAL INFORMATION (UNAUDITED)

Summarized quarterly financial information for 2015 and 2014 is as follows:

				Per Common Share				
							Trading Price Range	
Quarter Ended	Operating Revenues	Operating Income	Consolidated Net Income Attributable to Southern Company	Basic Earnings	Diluted Earnings	Dividends	High	Low
		(in millions)						
March 2015	**$ 4,183**	**$ 957**	**$ 508**	**$ 0.56**	**$ 0.56**	**$ 0.5250**	**$ 53.16**	**$ 43.55**
June 2015	**4,337**	**1,098**	**629**	**0.69**	**0.69**	**0.5425**	**45.44**	**41.40**
September 2015	**5,401**	**1,649**	**959**	**1.05**	**1.05**	**0.5425**	**46.84**	**41.81**
December 2015	**3,568**	**578**	**271**	**0.30**	**0.30**	**0.5425**	**47.50**	**43.38**
March 2014	$ 4,644	$ 700	$ 351	$ 0.39	$ 0.39	$ 0.5075	$ 44.00	$ 40.27
June 2014	4,467	1,103	611	0.68	0.68	0.5250	46.81	42.55
September 2014	5,339	1,278	718	0.80	0.80	0.5250	45.47	41.87
December 2014	4,017	561	283	0.31	0.31	0.5250	51.28	43.55

As a result of the revisions to the cost estimate for the Kemper IGCC, Southern Company recorded total pre-tax charges to income for the estimated probable losses on the Kemper IGCC of $183 million ($113 million after tax) in the fourth quarter 2015, $150 million ($93 million after tax) in the third quarter 2015, $23 million ($14 million after tax) in the second quarter 2015, $9 million ($6 million after tax) in the first quarter 2015, $70 million ($43 million after tax) in the fourth quarter 2014, $418 million ($258 million after tax) in the third quarter 2014, and $380 million ($235 million after tax) in the first quarter 2014. See Note 3 under "Integrated Coal Gasification Combined Cycle" for additional information.

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

SELECTED CONSOLIDATED FINANCIAL AND OPERATING DATA

For the Periods Ended December 2011 through 2015

	2015	2014	2013	2012	2011
Operating Revenues (in millions)	$ 17,489	$ 18,467	$ 17,087	$ 16,537	$ 17,657
Total Assets (in millions)[(a)(b)]	$ 78,318	$ 70,233	$ 64,264	$ 62,814	$ 58,986
Gross Property Additions (in millions)	$ 6,169	$ 6,522	$ 5,868	$ 5,059	$ 4,853
Return on Average Common Equity (percent)	11.68	10.08	8.82	13.10	13.04
Cash Dividends Paid Per Share of Common Stock	$ 2.1525	$ 2.0825	$ 2.0125	$ 1.9425	$ 1.8725
Consolidated Net Income Attributable to Southern Company (in millions)	$ 2,367	$ 1,963	$ 1,644	$ 2,350	$ 2,203
Earnings Per Share —					
Basic	$ 2.60	$ 2.19	$ 1.88	$ 2.70	$ 2.57
Diluted	2.59	2.18	1.87	2.67	2.55
Capitalization (in millions):					
Common stock equity	$ 20,592	$ 19,949	$ 19,008	$ 18,297	$ 17,578
Preferred and preference stock of subsidiaries and noncontrolling interests	1,390	977	756	707	707
Redeemable preferred stock of subsidiaries	118	375	375	375	375
Redeemable noncontrolling interests	43	39	—	—	—
Long-term debt[(a)]	24,688	20,644	21,205	19,143	18,492
Total (excluding amounts due within one year)	$ 46,831	$ 41,984	$ 41,344	$ 38,522	$ 37,152
Capitalization Ratios (percent):					
Common stock equity	44.0	47.5	46.0	47.5	47.3
Preferred and preference stock of subsidiaries and noncontrolling interests	3.0	2.3	1.8	1.8	1.9
Redeemable preferred stock of subsidiaries	0.3	0.9	0.9	1.0	1.0
Redeemable noncontrolling interests	0.1	0.1	—	—	—
Long-term debt[(a)]	52.6	49.2	51.3	49.7	49.8
Total (excluding amounts due within one year)	100.0	100.0	100.0	100.0	100.0
Other Common Stock Data:					
Book value per share	$ 22.59	$ 21.98	$ 21.43	$ 21.09	$ 20.32
Market price per share:					
High	$ 53.16	$ 51.28	$ 48.74	$ 48.59	$ 46.69
Low	41.40	40.27	40.03	41.75	35.73
Close (year-end)	46.79	49.11	41.11	42.81	46.29
Market-to-book ratio (year-end) (percent)	207.2	223.4	191.8	203.0	227.8
Price-earnings ratio (year-end) (times)	18.0	22.4	21.9	15.9	18.0
Dividends paid (in millions)	$ 1,959	$ 1,866	$ 1,762	$ 1,693	$ 1,601
Dividend yield (year-end) (percent)	4.6	4.2	4.9	4.5	4.0
Dividend payout ratio (percent)	82.7	95.0	107.1	72.0	72.7
Shares outstanding (in thousands):					
Average	910,024	897,194	876,755	871,388	856,898
Year-end	911,721	907,777	887,086	867,768	865,125
Stockholders of record (year-end)	131,771	137,369	143,800	149,628	155,198
Traditional Operating Company Customers (year-end) (in thousands):					
Residential	3,928	3,890	3,859	3,832	3,809
Commercial[(c)]	591	587	582	579	578
Industrial[(c)]	16	16	16	16	16
Other	11	11	10	9	9
Total	4,546	4,504	4,467	4,436	4,412
Employees (year-end)	26,703	26,369	26,300	26,439	26,377

(a) A reclassification of debt issuance costs from Total Assets to Long-term debt of $202 million, $139 million, $133 million, and $156 million is reflected for years 2014, 2013, 2012, and 2011, respectively, in accordance with ASU 2015-03. See Note 1 under "Recently Issued Accounting Standards" for additional information.
(b) A reclassification of deferred tax assets from Total Assets of $488 million, $143 million, $202 million, and $125 million is reflected for years 2014, 2013, 2012, and 2011, respectively, in accordance with ASU 2015-17. See Note 1 under "Recently Issued Accounting Standards" for additional information.
(c) A reclassification of customers from commercial to industrial is reflected for years 2011-2013 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.

	2015	2014	2013	2012	2011
Operating Revenues (in millions):					
Residential	**$ 6,383**	$ 6,499	$ 6,011	$ 5,891	$ 6,268
Commercial	**5,317**	5,469	5,214	5,097	5,384
Industrial	**3,172**	3,449	3,188	3,071	3,287
Other	**115**	133	128	128	132
Total retail	**14,987**	15,550	14,541	14,187	15,071
Wholesale	**1,798**	2,184	1,855	1,675	1,905
Total revenues from sales of electricity	**16,785**	17,734	16,396	15,862	16,976
Other revenues	**704**	733	691	675	681
Total	**$ 17,489**	$ 18,467	$ 17,087	$ 16,537	$ 17,657
Kilowatt-Hour Sales (in millions):					
Residential	**52,121**	53,347	50,575	50,454	53,341
Commercial	**53,525**	53,243	52,551	53,007	53,855
Industrial	**53,941**	54,140	52,429	51,674	51,570
Other	**897**	909	902	919	936
Total retail	**160,484**	161,639	156,457	156,054	159,702
Wholesale sales	**30,505**	32,786	26,944	27,563	30,345
Total	**190,989**	194,425	183,401	183,617	190,047
Average Revenue Per Kilowatt-Hour (cents):					
Residential	**12.25**	12.18	11.89	11.68	11.75
Commercial	**9.93**	10.27	9.92	9.62	10.00
Industrial	**5.88**	6.37	6.08	5.94	6.37
Total retail	**9.34**	9.62	9.29	9.09	9.44
Wholesale	**5.89**	6.66	6.88	6.08	6.28
Total sales	**8.79**	9.12	8.94	8.64	8.93
Average Annual Kilowatt-Hour Use Per Residential Customer	**13,318**	13,765	13,144	13,187	13,997
Average Annual Revenue Per Residential Customer	**$ 1,630**	$ 1,679	$ 1,562	$ 1,540	$ 1,645
Plant Nameplate Capacity Ratings (year-end) (megawatts)	**44,223**	46,549	45,502	45,740	43,555
Maximum Peak-Hour Demand (megawatts):					
Winter	**36,794**	37,234	27,555	31,705	34,617
Summer	**36,195**	35,396	33,557	35,479	36,956
System Reserve Margin (at peak) (percent)[(a)]	**33.2**	19.8	21.5	20.8	19.2
Annual Load Factor (percent)	**59.9**	59.6	63.2	59.5	59.0
Plant Availability (percent)[(b)]:					
Fossil-steam	**86.1**	85.8	87.7	89.4	88.1
Nuclear	**93.5**	91.5	91.5	94.2	93.0
Source of Energy Supply (percent):					
Coal	**32.3**	39.3	36.9	35.2	48.7
Nuclear	**15.2**	14.8	15.5	16.2	15.0
Hydro	**2.6**	2.5	3.9	1.7	2.1
Oil and gas	**43.5**	37.4	37.3	38.3	28.0
Purchased power	**6.4**	6.0	6.4	8.6	6.2
Total	**100.0**	100.0	100.0	100.0	100.0

(a) Beginning in 2014, system reserve margin is calculated to include unrecognized capacity.
(b) Beginning in 2012, plant availability is calculated as a weighted equivalent availability.

MANAGEMENT COUNCIL

The ages of the officers set forth below are as of December 31, 2015.

Thomas A. Fanning
Chairman, President, Chief Executive Officer, and Director
Age 58
Elected in 2003. Chairman, Chief Executive Officer, and Director since December 2010 and President since August 2010.

Art P. Beattie
Executive Vice President and Chief Financial Officer
Age 61
Elected in 2010. Executive Vice President and Chief Financial Officer since August 2010.

W. Paul Bowers
Executive Vice President
Age 59
Elected in 2001. Executive Vice President since February 2008 and Chief Executive Officer, President, and Director of Georgia Power since January 2011. Chairman of Georgia Power's Board of Directors since May 2014.

S. W. Connally, Jr.
Chairman, President, and Chief Executive Officer of Gulf Power
Age 46
Elected in 2012. Elected Chairman in July 2015 and President, Chief Executive Officer, and Director of Gulf Power since July 2012. Previously served as Senior Vice President and Chief Production Officer of Georgia Power from August 2010 through June 2012.

Mark A. Crosswhite
Executive Vice President
Age 53
Elected in 2010. Executive Vice President since December 2010 and President, Chief Executive Officer, and Director of Alabama Power since March 2014. Chairman of Alabama Power's Board of Directors since May 2014. Previously served as Executive Vice President and Chief Operating Officer of Southern Company from July 2012 through February 2014 and President, Chief Executive Officer, and Director of Gulf Power from January 2011 through June 2012.

Kimberly S. Greene
Executive Vice President
Age 49
Elected in 2013. Executive Vice President and Chief Operating Officer since March 2014. Previously served as President and Chief Executive Officer of SCS from April 2013 to February 2014. Before rejoining Southern Company, Ms. Greene previously served at Tennessee Valley Authority in a number of positions, most recently as Executive Vice President and Chief Generation Officer from 2011 through April 2013, and Group President of Strategy and External Relations from 2010 through 2011.

James Y. Kerr II
Executive Vice President and General Counsel
Age 51
Elected in 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
President and Chief Executive Officer of Southern Nuclear
Age 53
Elected in 2011. President and Chief Executive Officer of Southern Nuclear since July 2011. Before joining Southern Company, Mr. Kuczynski served at Exelon Corporation as the Senior Vice President of Engineering and Technical Services for Exelon Nuclear from February 2009 to June 2011.

Mark S. Lantrip
Executive Vice President
Age 61
Elected in 2014. President and Chief Executive Officer of SCS since March 2014. Previously served as Treasurer of Southern Company from October 2007 to February 2014 and Executive Vice President of SCS from November 2010 to March 2014.

Anthony L. Wilson
President and Chief Executive Officer of Mississippi Power
Age 51
Elected in 2015. President of Mississippi Power since October 2015 and Chief Executive Officer and Director since January 2016. Previously served as Executive Vice President of Mississippi Power from May 2015 to October 2015, Executive Vice President of Georgia Power from January 2012 to May 2015, and Vice President of Georgia Power from February 2007 to December 2011.

Christopher C. Womack
Executive Vice President
Age 57
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 27, 2015, for a term of one year or until their successors are elected and have qualified.

Transfer Agent

Wells Fargo Shareowner Services is Southern Company's transfer agent, dividend-paying agent, investment plan administrator and registrar. If you have questions concerning your registered Southern Company shareowner account, please contact:

Wells Fargo Shareowner Services
1110 Centre Pointe Curve, Suite 101
Mendota Heights, Minnesota 55120

Telephone: 1.800.554.7626
Website: **shareowneronline.com**

Southern Company Shareholder Relations

Dianne Perry
Telephone: 404.506.0965
Email: dperry@southernco.com

Southern Investment Plan

The Southern Investment Plan is a convenient way to become a Southern Company shareholder. Participants in the Plan can purchase additional shares in Southern Company through optional cash purchases and reinvestment of dividends. The Southern Investment Plan prospectus can be found at **www.southerncompany.com**.

Dividend Payments

Southern Company has paid dividends since 1948. Historically, dividends are declared and paid quarterly at the discretion of the Board of Directors.

Annual Meeting

The 2016 Annual Meeting of Stockholders will be held Wednesday, May 25, at 10 a.m. ET at The Lodge Conference Center at Callaway Gardens, Highway 18, Pine Mountain, Ga. 31822.

Auditors

Deloitte & Touche LLP
191 Peachtree St. NE
Suite 2000
Atlanta, GA 30303

Investor Information

For information about earnings and dividends, stock quotes and current news releases, please visit us at **www.investor.southerncompany.com**.

Institutional Investor Inquiries

Southern Company maintains an investor relations office in Atlanta, Georgia, 404-506-0780, to meet the information needs of institutional investors and securities analysts.

Electronic Delivery Of Proxy Materials

Any stockholder may enroll for electronic delivery of proxy materials by logging on at **www.icsdelivery.com/so**.

Environmental Information

Southern Company publishes information on its activities to meet environmental commitments at **www.southerncompany.com/planet-power/#reports**.

To Request Printed Materials, Write To:

Larry Monroe
Chief Environmental Officer & Senior Vice President
Research and Environmental Affairs
600 North 18th St.
Bin 14N-8195
Birmingham, AL 35203-2206

Common Stock

Southern Company common stock is listed on the NYSE under the ticker symbol SO. On December 31, 2015, Southern Company had 131,771 shareholders of record.

Visit our website at **www.southerncompany.com**

Visit our Corporate Responsibility Report at
www.southerncompany.com/corporateresponsibility

Follow us on Twitter at **www.twitter.com/southerncompany**

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