SOUTHERN CO
Form 10-K
February 27, 2014
Table of Contents Index to Financial Statements

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

þ ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934
For the Fiscal Year Ended December 31, 2013

OR

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

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

333-98553	Southern Power Company (A Delaware Corporation) 30 Ivan Allen Jr. Boulevard, N.W. Atlanta, Georgia 30308 (404) 506-5000	58-2598670

Table of Contents Index to Financial Statements

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

Title of each class	Registrant
Common Stock, $5 par value	The Southern Company
Class A preferred, cumulative, $25 stated capital 5.20% Series 5.83% Series 5.30% Series	Alabama Power Company
Class A Preferred Stock, non-cumulative, Par value $25 per share 6 1/8% Series	Georgia Power Company
Senior Notes 5.75% Series 2011A	Gulf Power Company
Depositary preferred shares, each representing one-fourth of a share of preferred stock, cumulative, $100 par value 5.25% Series	Mississippi Power Company

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

Title of each class			Registrant
Preferred stock, cumulative, $100 par value			Alabama Power Company
4.20% Series	4.60% Series	4.72% Series	
4.52% Series	4.64% Series	4.92% Series	
Preferred stock, cumulative, $100 par value			Mississippi Power Company
4.40% Series	4.60% Series		
4.72% Series			

1 As of December 31, 2013.

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

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

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

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

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

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

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

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

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

Table of Contents Index to Financial Statements

Aggregate market value of The Southern Company's common stock held by non-affiliates of The Southern Company at June 30, 2013: $38.6 billion. All of the common stock of the other registrants is held by The Southern Company. A description of each registrant's common stock follows:

Registrant	Description of Common Stock	Shares Outstanding at January 31, 2014
The Southern Company	Par Value $5 Per Share	887,940,630
Alabama Power Company	Par Value $40 Per Share	30,537,500
Georgia Power Company	Without Par Value	9,261,500
Gulf Power Company	Without Par Value	5,442,717
Mississippi Power Company	Without Par Value	1,121,000
Southern Power Company	Par Value $0.01 Per Share	1,000

Documents incorporated by reference: specified portions of The Southern Company's Definitive Proxy Statement on Schedule 14A relating to the 2014 Annual Meeting of Stockholders are incorporated by reference into PART III. In addition, specified portions of the Definitive Information Statements on Schedule 14C of Alabama Power Company, Georgia Power Company, and Mississippi Power Company relating to each of their respective 2014 Annual Meetings of Shareholders are incorporated by reference into PART III.

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

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

Table of Contents

Table of Contents Index to Financial Statements

DEFINITIONS

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

Term	Meaning
2010 ARP	Alternative Rate Plan approved by the Georgia PSC for Georgia Power for the years 2011 through 2013
2013 ARP	Alternative Rate Plan approved by the Georgia PSC for Georgia Power for the years 2014 through 2016
Alabama Power	Alabama Power Company
Clean Air Act	Clean Air Act Amendments of 1990
Code	Internal Revenue Code of 1986, as amended
CPCN	Certificate of Public Convenience and Necessity
CWIP	Construction Work in Progress
Dalton	City of Dalton, Georgia, acting by and through its Board of Water, Light, and Sinking Fund Commissioners
DOE	United States Department of Energy
Duke Energy Florida	Duke Energy Florida, Inc.
EPA	United States Environmental Protection Agency
FERC	Federal Energy Regulatory Commission
FMPA	Florida Municipal Power Agency
Georgia Power	Georgia Power Company
Gulf Power	Gulf Power Company
IBEW	International Brotherhood of Electrical Workers
IGCC	Integrated coal gasification combined cycle
IIC	Intercompany Interchange Contract
IPP	Independent Power Producer
IRP	Integrated Resource Plan
Kemper IGCC	IGCC facility under construction in Kemper County, Mississippi
KUA	Kissimmee Utility Authority
KW	Kilowatt
KWH	Kilowatt-hour
MATS rule	Mercury and Air Toxics Standards rule
MEAG Power	Municipal Electric Authority of Georgia
Mississippi Power	Mississippi Power Company
MW	Megawatt
NRC	U.S. Nuclear Regulatory Commission
OPC	Oglethorpe Power Corporation
OUC	Orlando Utilities Commission
Plant Vogtle Units 3 and 4	Two new nuclear generating units under construction at Plant Vogtle
power pool	The operating arrangement whereby the integrated generating resources of the traditional operating companies and Southern Power Company are subject to joint commitment and dispatch in order to serve their combined load obligations
PowerSouth	PowerSouth Energy Cooperative
PPA	Power Purchase Agreement

DEFINITIONS
(continued)

Term	Meaning
PSC	Public Service Commission
registrants	Southern Company, Alabama Power, Georgia Power, Gulf Power, Mississippi Power, and Southern Power Company
RUS	Rural Utilities Service
SCS	Southern Company Services, Inc. (the system service company)
SEC	Securities and Exchange Commission
SEGCO	Southern Electric Generating Company
SEPA	Southeastern Power Administration
SERC	Southeastern Electric Reliability Council
SMEPA	South Mississippi Electric Power Association
Southern Company	The Southern Company
Southern Company system	Southern Company, the traditional operating companies, Southern Power, SEGCO, Southern Nuclear, SCS, SouthernLINC Wireless, and other subsidiaries
Southern Holdings	Southern Company Holdings, Inc.
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

CAUTIONARY STATEMENT REGARDING
FORWARD-LOOKING INFORMATION

This Annual Report on Form 10-K contains forward-looking statements. Forward-looking statements include, among other things, statements concerning retail sales, retail rates, the strategic goals for the wholesale business, customer growth, economic recovery, fuel and environmental cost recovery and other rate actions, current and proposed environmental regulations and related estimated expenditures, access to sources of capital, projections for the qualified pension plan, postretirement benefit plan, and nuclear decommissioning trust fund contributions, financing activities, completion dates of construction projects, plans and estimated costs for new generation resources, filings with state and federal regulatory authorities, impact of the American Taxpayer Relief Act of 2012, estimated sales and purchases under new power sale and purchase agreements, and estimated construction and other 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 including regulation of water, coal combustion residuals, and emissions of sulfur, nitrogen, carbon, soot, particulate matter, hazardous air pollutants, including mercury, and other substances, 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 the pending EPA civil actions against certain Southern Company subsidiaries, FERC matters, and Internal Revenue Service 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 recent recession, population and business growth (and declines), the effects of energy conservation 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;
- ability to control costs and avoid cost overruns during the development and construction of facilities, which include the development and construction of facilities with designs that have not been finalized or previously constructed, including changes in labor costs and productivity factors, adverse weather conditions, shortages and inconsistent quality of equipment, materials, and labor, contractor or supplier delay or non-performance under construction or other agreements, delays associated with start-up activities, including major equipment failure, system integration, and operations, and/or unforeseen engineering problems;
- ability to construct facilities in accordance with the requirements of permits and licenses and to satisfy any operational and environmental performance standards, including the requirements of tax credits and other incentives;
- 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;
- regulatory approvals and actions related to Plant Vogtle Units 3 and 4, including Georgia PSC approvals, and NRC actions;
- actions related to cost recovery for the Kemper IGCC, including actions relating to proposed securitization, Mississippi PSC approval of Mississippi Power's proposed rate recovery plan, as ultimately amended, which includes

the ability to complete the proposed sale of an interest in the Kemper IGCC to SMEPA, the ability to utilize bonus depreciation, which currently requires that the Kemper IGCC be placed in service in 2014, and satisfaction of requirements to utilize investment tax credits and grants;

- Mississippi PSC review of the prudence of Kemper IGCC costs;
- the outcome of any legal or regulatory proceedings regarding the Mississippi PSC's issuance of the CPCN for the Kemper IGCC, the settlement agreement between Mississippi Power and the Mississippi PSC, or the 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;
- the inherent risks involved in operating and constructing nuclear generating facilities, including environmental, health, regulatory, natural disaster, terrorism, or 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 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 terrorist incidents and the threat of terrorist incidents, including cyber intrusion;
- interest rate fluctuations and financial market conditions and the results of financing efforts, including Southern Company's and its subsidiaries' credit ratings;
- the impacts of any potential U.S. credit rating downgrade or other 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 and its subsidiaries to obtain additional generating capacity at competitive prices;
- catastrophic events such as fires, earthquakes, explosions, floods, hurricanes, 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 filed by the registrants from time to time with the SEC.

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

PART I

Item 1. BUSINESS

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

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

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

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

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

In addition, Southern Company owns all of the common stock of Southern Power Company, which is also an operating public utility company. Southern Power constructs, acquires, owns, and manages generation assets, including renewable energy projects, and sells electricity at market-based rates in the wholesale market. Southern Power Company is a corporation organized under the laws of Delaware on January 8, 2001 and was admitted to do business in the States of Alabama, Florida, and Georgia on January 10, 2001, in the State of Mississippi on January 30, 2001, in the State of North Carolina on February 19, 2007, and in the State of South Carolina on March 31, 2009. Certain of Southern Power Company's subsidiaries are also admitted to do business in the States of California, Nevada, New Mexico, and Texas.

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 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.

Alabama Power and Georgia Power each own 50% of the outstanding common stock of SEGCO. SEGCO is an operating public utility company that owns electric generating units with an aggregate capacity of 1,019,680 KWs at Plant Gaston on the Coosa River near Wilsonville, Alabama. Alabama Power and Georgia Power are each entitled to one-half of SEGCO's capacity and energy. Alabama Power acts as SEGCO's agent in the operation of SEGCO's units and furnishes fuel to SEGCO for its units. SEGCO also owns one 230,000 volt transmission line extending from Plant Gaston to the Georgia state line at which point connection is made with the Georgia Power transmission line system.

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

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

The Southern Company System

Traditional Operating Companies

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

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

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

Southern Company, each traditional operating company, Southern Power Company, Southern Nuclear, SEGCO, and other subsidiaries have contracted with SCS to furnish, at direct or allocated cost and upon request, the following services: general and design engineering, operations, purchasing, accounting, finance and treasury, tax, information technology, marketing, auditing, insurance and pension administration, human resources, systems and procedures, digital wireless communications, and other services with respect to business and operations, construction management, and power pool transactions. Southern Power Company and SouthernLINC Wireless have also secured from the traditional operating companies certain services which are furnished at cost and, in the case of Southern Power Company, which are subject to FERC regulations.

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

Southern Power

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

In June 2012, Southern Power completed construction of Plant Nacogdoches, a biomass generating plant near Sacul, Texas with a nameplate capacity of approximately 116 MWs. Nacogdoches Power, LLC, a wholly-owned subsidiary of Southern Power Company, has a PPA covering the entire output of the plant from 2012 through 2032.

In December 2012, Southern Power completed construction of Plant Cleveland Units 1 through 4, a combustion turbine natural gas generating plant, in Cleveland County, North Carolina. The plant has a nameplate capacity of 720 MWs. Southern Power has long-term PPAs for 540 MWs of the generating capacity of the plant (180 MWs through 2031 and 360 MWs through 2036).

In 2012, Southern Power and Turner Renewable Energy, Inc. (TRE), through Southern Turner Renewable Energy LLC (STR), a jointly-owned subsidiary owned 90% by a subsidiary of Southern Power Company, acquired all of the outstanding membership interests of Apex Nevada Solar, LLC (Apex), Spectrum Nevada Solar, LLC (Spectrum), and Granville Solar, LLC (Granville). Apex owns a 20-MW solar photovoltaic facility in North Las Vegas, Nevada, which began commercial operation in July 2012. Apex has a PPA covering the entire output of the plant from 2012 through 2037. Granville owns a 2.5-MW solar photovoltaic facility in Oxford, North Carolina, which began commercial operation in October 2012. Granville has a PPA covering the entire output of the plant from 2012 through 2032. Spectrum owns a 30-MW solar photovoltaic facility in North Las Vegas, Nevada, which began commercial operation on September 23, 2013. Spectrum has a PPA covering the entire output of the plant from 2013 through 2038.

On April 23, 2013, Southern Power and TRE, through STR, acquired all of the outstanding membership interests of Campo Verde Solar, LLC (Campo Verde). Campo Verde owns an approximately 139-MW solar facility in Southern California, which began commercial operation on October 25, 2013. The output of the plant is contracted under a 20-year PPA with San Diego Gas & Electric Company, a subsidiary of Sempra Energy.

On August 27, 2013, Southern Power and TRE, through STR, entered into a purchase agreement with Sun Edison, LLC, the developer of the project, which provides for the acquisition of all of the outstanding membership interests of Adobe Solar, LLC (Adobe) by STR. Adobe is constructing an approximately 20-MW solar generating facility in Kern County, California. The solar facility is expected to begin commercial operation in spring 2014. Southern Power's purchase of Adobe for approximately $100 million is expected to occur in spring 2014. The output of the plant is contracted under a 20-year PPA with Southern California Edison.

As of December 31, 2013, Southern Power had 8,924 MWs of nameplate capacity in commercial operation.

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

Other Businesses

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

SouthernLINC Wireless provides digital wireless communications for use by Southern Company and its subsidiary companies and markets its services to non-affiliates within the Southeast. SouthernLINC Wireless delivers multiple wireless communication options including push to talk, cellular service, text messaging, wireless internet access, and wireless data. Its system covers approximately 127,000 square miles in the Southeast. SouthernLINC Wireless also provides wholesale fiber optic solutions to telecommunication providers in the Southeast under the name Southern Telecom.

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

Construction Programs

The subsidiary companies of Southern Company are engaged in continuous construction programs to accommodate existing and estimated future loads on their respective systems. For estimated construction and environmental expenditures for the periods 2014 through 2016, see MANAGEMENT'S DISCUSSION AND ANALYSIS – FINANCIAL CONDITION AND LIQUIDITY – "Capital Requirements and Contractual Obligations" of Southern Company, each traditional operating company, and Southern Power in Item 7 herein. The Southern Company system's construction program consists of capital investment and capital expenditures to comply with environmental statutes and regulations. In 2014, the construction program is expected to be apportioned approximately as follows:

	Southern Company system * (in millions)	Alabama Power	Georgia Power	Gulf Power	Mississippi Power
New Generation	$1,148	$—	$658	$—	$490
Environmental **	1,457	505	543	255	154
Transmission & Distribution Growth	412	121	254	22	15
Maintenance (Generation, Transmission, and Distribution)	1,858	870	792	108	88
Nuclear Fuel	325	141	184	—	—
General Plant	222	97	106	9	10
	5,422	1,734	2,537	394	757
Southern Power	477	—	—	—	—
Other subsidiaries	163	—	—	—	—
Total	$6,062	$1,734	$2,537	$394	$757

* These amounts include the amounts for the traditional operating companies (as detailed in the table above) as well as the amounts for Southern Power and the other subsidiaries. See "Other Businesses" herein for additional information.

** Reflects cost estimates for environmental regulations. The Southern Company system continues to monitor the development of the EPA's proposed water and coal combustion residuals rules and to evaluate compliance options. See MANAGEMENT'S DISCUSSION AND ANALYSIS – FUTURE EARNINGS POTENTIAL – "Environmental Matters – Environmental Statutes and Regulations" and FINANCIAL CONDITION AND LIQUIDITY – "Capital Requirements and Contractual Obligations" of Southern Company and each traditional operating company in Item 7 herein for additional information.

The construction programs are subject to periodic review and revision, and actual construction costs may vary from these estimates because of numerous factors. These factors include: changes in business conditions; changes in load projections; changes in the expected environmental compliance program; 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 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.

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-its-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 changes in labor costs and productivity factors, adverse weather conditions, shortages and inconsistent quality of equipment, materials, and labor, contractor or supplier delay or non-performance under construction or other agreements, delays associated with start-up activities, including major equipment failure, system integration, and operations, and/or unforeseen engineering problems.

See "Regulation – Environmental Statutes and Regulations" herein for additional information with respect to certain existing and proposed environmental requirements and PROPERTIES – "Jointly-Owned Facilities" in Item 2 herein for additional information concerning Alabama Power's, Georgia Power's, and Southern Power's joint ownership of certain generating units and related facilities with certain non-affiliated utilities. See Note 3 to the financial statements of Southern Company and Georgia Power under "Retail Regulatory Matters – Georgia Power – Nuclear Construction" and "Retail Regulatory Matters – Nuclear Construction," respectively, for additional information regarding Georgia Power’s construction of Plant Vogtle Units 3 and 4. Also see Note 3 to the financial statements of Southern Company and Mississippi Power under "Integrated Coal Gasification Combined Cycle" for additional information regarding Mississippi Power’s construction of the Kemper IGCC.

Financing Programs

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

Fuel Supply

The traditional operating companies' and SEGCO's supply of electricity is primarily fueled by natural gas and coal. Southern Power's supply of electricity is primarily fueled by natural gas. See MANAGEMENT'S DISCUSSION AND ANALYSIS – RESULTS OF OPERATION – "Electricity Business – Fuel and Purchased Power Expenses" of Southern Company and MANAGEMENT'S DISCUSSION AND ANALYSIS – RESULTS OF OPERATION – "Fuel and Purchased Power Expenses" of each traditional operating company in Item 7 herein for information regarding the electricity generated and the average cost of fuel in cents per net KWH generated for the years 2011 through 2013.

The traditional operating companies have agreements in place from which they expect to receive substantially all of their coal burn requirements in 2014. These agreements have terms ranging between one and eight years. In 2013, the weighted average sulfur content of all coal burned by the traditional operating companies was 0.75% sulfur. This sulfur level, along with banked and purchased sulfur dioxide allowances, allowed the traditional operating companies to remain within limits set by Phase I of the Clean Air Interstate Rule (CAIR) under the Clean Air Act. In 2013, the Southern Company system did not purchase any sulfur dioxide allowances, annual nitrogen oxide emission allowances, or seasonal nitrogen oxide emission allowances from the market. As any additional environmental regulations are proposed that impact the utilization of coal, the traditional operating companies' fuel mix will be monitored to help ensure that the traditional operating companies remain in compliance with applicable laws and regulations. Additionally, Southern Company and the traditional operating companies will continue to evaluate the need to purchase additional emissions allowances, the timing of capital expenditures for emissions control equipment, and potential unit retirements and replacements. See MANAGEMENT'S DISCUSSION AND ANALYSIS – FUTURE EARNINGS POTENTIAL – "Environmental Matters" of Southern Company, each traditional operating company, and Southern Power in Item 7 herein for additional information on environmental matters.

SCS, acting on behalf of the traditional operating companies and Southern Power Company, has agreements in place for the natural gas burn requirements of the Southern Company system. For 2014, SCS has contracted for 431 billion cubic feet of natural gas supply under agreements with remaining terms up to seven years. In addition to natural gas supply, SCS has contracts in place for both firm natural gas transportation and storage. Management believes these contracts provide sufficient natural gas supplies, transportation, and storage to ensure normal operations of the Southern Company system's natural gas generating units.

Alabama Power and Georgia Power have numerous contracts covering a portion of their nuclear fuel needs for uranium, conversion services, enrichment services, and fuel fabrication. These contracts have varying expiration dates and most of them are for less than 10 years. Management believes sufficient capacity for nuclear fuel supplies and processing exists to preclude the impairment of normal operations of the Southern Company system's nuclear generating units.

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

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

Territory Served by the Traditional Operating Companies and Southern Power

The territory in which the traditional operating companies provide electric service comprises most of the states of Alabama and Georgia together with the northwestern portion of Florida and southeastern Mississippi. In this territory there are non-affiliated electric distribution systems that obtain some or all of their power requirements either directly or indirectly from the traditional operating companies. The territory has an area of approximately 120,000 square miles and an estimated population of approximately 16 million. Southern Power sells electricity at market-based rates in the wholesale market primarily to investor-owned utilities, IPPs, municipalities, and electric cooperatives.

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

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

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

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

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

The RUS has authority to make loans to cooperative associations or corporations to enable them to provide electric service to customers in rural sections of the country. There are 71 electric cooperative organizations operating in the territory in which the traditional operating companies provide electric service at retail or wholesale.

One of these organizations, PowerSouth, is a generating and transmitting cooperative selling power to several distributing cooperatives, municipal systems, and other customers in south Alabama and northwest Florida. PowerSouth owns generating units with approximately 2,027 MWs of nameplate capacity, including an undivided 8.16% ownership interest in Alabama Power's Plant Miller Units 1 and 2. PowerSouth's facilities were financed with RUS loans secured by long-term contracts requiring distributing cooperatives to take their requirements from PowerSouth to the extent such energy is available. See PROPERTIES – "Jointly-Owned Facilities" in Item 2 herein for details of Alabama Power's joint-ownership with PowerSouth of a portion of Plant Miller.

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

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

Mississippi Power has an interchange agreement with SMEPA, a generating and transmitting cooperative, pursuant to which various services are provided. In 2010, Mississippi Power and SMEPA entered into an asset purchase agreement whereby SMEPA agreed to purchase a 17.5% undivided interest in the Kemper IGCC. In February 2012, the Mississippi PSC approved the sale and transfer of 17.5% of the Kemper IGCC to SMEPA. In June 2012, Mississippi Power and SMEPA signed an amendment to the asset purchase agreement whereby SMEPA reduced its purchase commitment percentage from a 17.5% to a 15% undivided interest in the Kemper IGCC, subject to approval by the Mississippi PSC. On March 29, 2013, Mississippi Power and SMEPA signed an amendment to the asset purchase agreement whereby Mississippi Power and SMEPA agreed to amend the PPA entered into by the parties in April 2011 to reduce the capacity amounts to be received by SMEPA by half (approximately 75 MWs) effective with the sale and transfer of an undivided interest in the Kemper IGCC to SMEPA. On December 24, 2013, Mississippi Power and SMEPA agreed to extend SMEPA's option to purchase through December 31, 2014. The sale and transfer of an interest in the Kemper IGCC to SMEPA is subject to approval by the Mississippi PSC. The closing of this transaction is conditioned upon execution of a joint ownership and operating agreement, receipt of all construction permits, appropriate regulatory approvals, financing, and other conditions.

There are also 65 municipally-owned electric distribution systems operating in the territory in which the traditional operating companies provide electric service at retail or wholesale.

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

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

Southern Power has PPAs with some of the traditional operating companies and with other investor-owned utilities, IPPs, municipalities, electric cooperatives, and an energy marketing firm. See MANAGEMENT'S DISCUSSION AND ANALYSIS – FUTURE EARNINGS POTENTIAL – "Power Sales Agreements" of Southern Power in Item 7 herein for additional information concerning Southern Power's PPAs.

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

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

Competition

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

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

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

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

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

Alabama Power currently has cogeneration contracts in effect with 12 industrial customers. Under the terms of these contracts, Alabama Power purchases excess energy generated by such companies. During 2013, Alabama Power purchased approximately 151 million KWHs from such companies at a cost of $5.0 million.

Georgia Power currently has contracts in effect with 25 small power producers whereby Georgia Power purchases their excess generation. During 2013, Georgia Power purchased 393 million KWHs from such companies at a cost of $25 million. Georgia Power also has a PPA for electricity with one cogeneration facility. Payments are subject to reductions for failure to meet minimum capacity output. During 2013, Georgia Power purchased 73 million KWHs at a cost of $16 million from this facility.

Also during 2013, Georgia Power purchased energy from four customer-owned generating facilities. These customers provide only energy to Georgia Power and make no capacity commitment and are not dispatched by Georgia Power. During 2013, Georgia Power purchased a total of 34 million KWHs from the four customers at a cost of approximately $1 million.

Gulf Power currently has agreements in effect with various industrial, commercial, and qualifying facilities pursuant to which Gulf Power purchases "as available" energy from customer-owned generation. During 2013, Gulf Power purchased 266 million KWHs from such companies for approximately $10.2 million.

Mississippi Power currently has a cogeneration agreement in effect with one of its industrial customers. Under the terms of this contract, Mississippi Power purchases any excess generation. During 2013, Mississippi Power did not purchase any excess generation from this customer.

Seasonality

The demand for electric power generation is affected by seasonal differences in the weather. At the traditional operating companies and Southern Power, the demand for power peaks during the summer months, with market prices reflecting the demand of power and available generating resources at that time. Power demand peaks can also be recorded during the winter. As a result, the overall operating results of Southern Company, the traditional operating companies, and Southern Power in the future may fluctuate substantially on a seasonal basis. In addition, Southern Company, the traditional operating companies, and Southern Power have historically sold less power when weather conditions are milder.

Regulation

State Commissions

The traditional operating companies are subject to the jurisdiction of their respective state PSCs. The PSCs have broad powers of supervision and regulation over public utilities operating in the respective states, including their rates, service regulations, sales of securities (except for the Mississippi PSC), and, in the cases of the Georgia PSC and the Mississippi PSC, in part, retail service territories. See "Territory Served by the Traditional Operating Companies and Southern Power" and "Rate Matters" herein for additional information.

Federal Power Act

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

Alabama Power and Georgia Power are also subject to the provisions of the Federal Power Act or the earlier Federal Water Power Act applicable to licensees with respect to their hydroelectric developments. Among the hydroelectric projects subject to licensing by the FERC are 14 existing Alabama Power generating stations having an aggregate installed capacity of 1,662,400 KWs and 18 existing Georgia Power generating stations having an aggregate installed capacity of 1,087,296 KWs.

In 2005, Alabama Power filed two applications with the FERC for new 50-year licenses for its seven hydroelectric developments on the Coosa River (Weiss, Henry, Logan Martin, Lay, Mitchell, Jordan, and Bouldin) and for the Lewis Smith and Bankhead developments on the Warrior River. The FERC licenses for all of these nine projects expired in 2007. Since the FERC did not act on Alabama Power's new license applications prior to the expiration of the existing licenses, the FERC is required by law to issue annual licenses to Alabama Power, under the terms and conditions of the existing licenses, until action is taken on the new license applications.

The FERC issued annual licenses for the Coosa developments and the Warrior River developments in 2007. These annual licenses are automatically renewed each year without further action by the FERC to allow Alabama Power to continue operation of the projects under the terms of the previous license while the FERC completes review of the applications for new licenses. Though the Coosa application remains pending before the FERC, in 2010, the FERC issued a new 30 year license to Alabama Power for the Warrior River developments. In 2010, the Smith Lake Improvement and Stakeholders' Association filed a request for rehearing of the FERC order granting the new Warrior license. Following the FERC's denials of the requests for rehearings, on March 18, 2013, the Smith Lake Improvement and Stakeholders' Association filed an appeal to the U.S. Court of Appeals for the District of Columbia Circuit regarding the FERC's orders related to the Warrior River relicensing proceedings.

In 2011, Alabama Power filed an application with the FERC to relicense the Martin Dam project located on the Tallapoosa River. The Martin license expired on June 8, 2013. Since the FERC did not act on Alabama Power's license application prior to the expiration of the existing license, the FERC issued an annual license to Alabama Power for the Martin Dam project on June 18, 2013.

On August 16, 2013, Alabama Power filed an application with the FERC to relicense the Holt hydroelectric project located on the Warrior River. The current Holt license will expire on August 31, 2015.

In December 2012, Georgia Power filed an application with the FERC to relicense the Bartlett's Ferry project located on the Chattahoochee River near Columbus, Georgia. The current Bartlett's Ferry license will expire on December 14, 2014.

The ultimate outcome of these matters cannot be determined at this time. See MANAGEMENT'S DISCUSSION AND ANALYSIS – FUTURE EARNINGS POTENTIAL – "FERC Matters" of Alabama Power in Item 7 herein for additional information.

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

Licenses for all projects, excluding those discussed above, expire in the period 2023-2034 in the case of Alabama Power's projects and in the period 2020-2039 in the case of Georgia Power's projects.

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

Nuclear Regulation

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

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

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

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

Environmental Statutes and Regulations

The Southern Company system's 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. Compliance with these existing environmental requirements involves significant capital and operating costs, a major portion of which is expected to be recovered through existing ratemaking provisions or long-term wholesale agreements for the traditional operating companies or market-based rates for Southern Power. There is no assurance, however, that all such costs will be recovered.

Compliance with the federal Clean Air Act and resulting regulations has been, and will continue to be, a significant focus for Southern Company, each traditional operating company, Southern Power, and SEGCO. In addition, existing environmental laws and regulations may be changed or new laws and regulations may be adopted or otherwise become applicable to the Southern Company system, including laws and regulations designed to address air quality, water, management of waste materials and coal combustion residuals, global climate change, or other environmental and health concerns. See MANAGEMENT'S DISCUSSION AND ANALYSIS – FUTURE EARNINGS POTENTIAL – "Environmental Matters" of Southern Company and each of the traditional operating companies in Item 7 herein for additional information about the Clean Air Act and other environmental issues, including, but not limited to, the litigation brought by the EPA under the New Source Review provisions of the Clean Air Act, proposed and final regulations related to air quality, water, greenhouse gases, and coal combustion residuals. Also see MANAGEMENT'S DISCUSSION AND ANALYSIS – FUTURE EARNINGS POTENTIAL – "Environmental Matters" of Southern Power in Item 7 herein for additional information about environmental issues and climate change regulation.

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 and regulations relating to global climate change that are promulgated, including the proposed environmental regulations; 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, and adding or changing fuel sources for certain existing units. Also see MANAGEMENT'S DISCUSSION AND ANALYSIS – FUTURE EARNINGS POTENTIAL – "Environmental Matters" of Southern Company, each of the traditional operating companies, and Southern Power in Item 7 herein for additional information. The ultimate outcome of these matters cannot be determined at this time.

SEGCO is jointly owned by Alabama Power and Georgia Power. As part of its environmental compliance strategy, SEGCO plans to add natural gas as the primary fuel source for its generating units in 2015. The capacity of SEGCO's units is sold equally to Alabama Power and Georgia Power through a PPA. If such compliance costs cannot continue to be recovered by Alabama Power or Georgia Power through retail rates, they could have a material financial impact on the financial statements of Southern Company and the applicable traditional operating company. See Note 4 to the financial statements of Alabama Power and Georgia Power for additional information.

Compliance with any new federal or state legislation or regulations relating to air quality, water, coal combustion residuals, global climate change, or other environmental and health concerns could significantly affect the Southern Company system. Although new or revised environmental legislation or regulations could affect many areas of the electric utilities' 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. See "Construction Program" herein for additional information.

Rate Matters

Rate Structure and Cost Recovery Plans

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

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

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

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

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

The traditional operating companies and Southern Power Company and certain of its generation subsidiaries are authorized by the FERC to sell power to non-affiliates, including short-term opportunity sales, at market-based prices. Specific FERC approval must be obtained with respect to a market-based contract with an affiliate.

Mississippi Power serves long-term contracts with rural electric cooperative associations and municipalities located in southeastern Mississippi under cost-based electric tariffs which are subject to regulation by the FERC. The contracts with these wholesale customers represented 22% of Mississippi Power's operating revenues in 2013 and are largely subject to rolling 10-year cancellation notices.

Integrated Resource Planning

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

Certain of the traditional operating companies periodically file IRPs with their respective state PSC as discussed below.

Georgia Power

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

See MANAGEMENT'S DISCUSSION AND ANALYSIS – FUTURE EARNINGS POTENTIAL – "PSC Matters – Georgia Power – Rate Plans" of Southern Company and Note 3 to the financial statements of Southern Company under "Georgia Power – Nuclear Construction" and MANAGEMENT'S DISCUSSION AND ANALYSIS – FUTURE EARNINGS POTENTIAL – "PSC Matters – Integrated Resource Plans," "– Renewables Development," and "– Nuclear Construction" of Georgia Power in Item 7 herein for additional information.

Gulf Power

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

Gulf Power's most recent 10-year site plan was classified by the Florida PSC as "suitable" in October 2013. Gulf Power's most recent 10-year site plan and environmental compliance plan identify environmental regulations and potential legislation or regulation that would impose mandatory restrictions on greenhouse gas emissions. See MANAGEMENT'S DISCUSSION AND ANALYSIS – FUTURE EARNINGS POTENTIAL – "Environmental Matters – Environmental Statutes and Regulations – Air Quality," "Environmental Matters – Environmental Statutes and Regulations – Coal Combustion Residuals," and "Environmental Matters – Global Climate Issues" of Gulf Power in Item 7 herein. Gulf Power continues to evaluate the economics of various potential planning scenarios for units at certain Gulf Power coal-fired generating plants as EPA and other regulations develop.

At least every five years, the Florida PSC must conduct proceedings to establish numerical goals for all investor-owned electric utilities and certain municipal or cooperative electric utilities in the state to reduce the growth rates of weather-sensitive peak demand, to reduce and control the growth rates of electric consumption, and to increase the conservation of expensive resources, such as petroleum fuels. Overall residential KWs and KWH goals and overall commercial/industrial KWs and KWH goals for each utility are set by the Florida PSC for each year over a 10-year period. The goals are to be based on an estimate of the total cost effective KWs and KWH savings reasonably achievable through demand-side management in each utility's service territory over a 10-year period. Once goals have been set, each affected utility must develop and submit plans and programs to meet the overall goals within its service territory to the Florida PSC for review and approval. Once approved, the utilities are required to submit periodic reports which the Florida PSC then uses to prepare its annual report to the Florida Governor and legislature of the goals that have been established and the progress towards meeting those goals.

In 2009, the Florida PSC adopted new numerical conservation goals for Gulf Power along with other electric utilities in the state. Gulf Power's plans and programs to meet the new goals were approved by the Florida PSC. The costs of implementing Gulf Power's conservation plans and programs are recovered through specific conservation recovery rates set annually by the Florida PSC.

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

Mississippi Power

Mississippi Power's 2010 IRP indicated that Mississippi Power plans to construct the Kemper IGCC to meet its identified needs, to add environmental controls at Plant Daniel Units 1 and 2, to defer environmental controls at Plant Watson Units 4 and 5, and to continue operation of the combined cycle Plant Daniel Units 3 and 4. See MANAGEMENT'S DISCUSSION AND ANALYSIS – FUTURE EARNINGS POTENTIAL – "Environmental Matters – Environmental Statutes and Regulations – Air Quality" and "Environmental Matters – Global Climate Issues" of Mississippi Power in Item 7 herein. Depending on the final requirements in the anticipated EPA regulations and any legislation or regulation relating to greenhouse gas emissions, as well as estimates of long-term fuel prices, Mississippi Power may conclude that it is more economical to discontinue burning coal at certain coal-fired generating units than to install the required controls. The ultimate outcome of these matters cannot be determined at this time.

Mississippi Baseload Act

In the 2008 regular session of the Mississippi legislature, a bill was passed and signed by the Governor to enhance the Mississippi PSC's authority to facilitate development and construction of base load generation in the State of Mississippi (Baseload Act). The Baseload Act authorizes, but does not require, the Mississippi PSC to adopt a cost recovery mechanism that includes in retail base rates, prior to and during construction, all or a portion of the prudently incurred pre-construction and construction costs incurred by a utility in constructing a base load electric generating plant. Prior to the passage of the Baseload Act, such costs would traditionally be recovered only after the plant was placed in service. The Baseload Act also provides for periodic prudence reviews by the Mississippi PSC and prohibits the cancellation of any such generating plant without the approval of the Mississippi PSC. In the event of cancellation of the construction of the plant without approval of the Mississippi PSC, the Baseload Act authorizes the Mississippi PSC to make a public interest determination as to whether and to what extent the utility will be afforded rate recovery for costs incurred in connection with such cancelled generating plant. There are legal challenges to the constitutionality of the Baseload Act currently pending before the Mississippi Supreme Court. The ultimate impact of this legislation on Southern Company and Mississippi Power will depend on the outcome of any legal challenges and cannot be determined at this time.

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

For information regarding certain legal challenges to the Baseload Act, see Note 3 to the financial statements of Southern Company under "Integrated Coal Gasification Combined Cycle – Baseload Act" and Note 3 to the financial statements of Mississippi Power under "Retail Regulatory Matters - Baseload Act" in Item 8 herein.

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

Employee Relations

The Southern Company system had a total of 26,300 employees on its payroll at December 31, 2013.

	Employees at December 31, 2013
Alabama Power	6,896
Georgia Power	7,886
Gulf Power	1,410
Mississippi Power	1,344
SCS	4,459
Southern Nuclear	4,049
Southern Power*	0
Other	256
Total	26,300

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

The traditional operating companies have separate agreements with local unions of the IBEW generally covering wages, working conditions, and procedures for handling grievances and arbitration. These agreements apply with certain exceptions to operating, maintenance, and construction employees.

Alabama Power has agreements with the IBEW in effect through August 15, 2014. Upon notice given at least 60 days prior to that date, negotiations may be initiated with respect to agreement terms to be effective after such date.

Georgia Power has an agreement with the IBEW covering wages and working conditions, which is in effect through June 30, 2016.

Gulf Power has an agreement with the IBEW covering wages and working conditions, which is in effect through September 14, 2014. Upon notice given at least 60 days prior to that date, negotiations may be initiated with respect to agreement terms to be effective after such date.

Mississippi Power has an agreement with the IBEW covering wages and working conditions, which is in effect through May 1, 2019. On February 11, 2013, Mississippi Power signed a separate agreement with the IBEW related solely to the Kemper IGCC, which is in effect through March 15, 2016.

Southern Nuclear has an agreement with the IBEW covering certain employees at Plants Hatch and Vogtle which is in effect through June 30, 2016. A five-year agreement between Southern Nuclear and the IBEW representing certain employees at Plant Farley is in effect through August 15, 2014. Upon notice given at least 60 days prior to that date, negotiations may be initiated with respect to agreement terms to be effective after such date.

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

Item 1A. RISK FACTORS

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

UTILITY REGULATORY, LEGISLATIVE, AND LITIGATION RISKS

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

Southern Company and its subsidiaries, including the traditional operating companies and Southern Power, are subject to substantial regulation from federal, state, and local regulatory agencies. Southern Company and its subsidiaries are required to comply with numerous laws and regulations and to obtain numerous permits, approvals, and certificates from the governmental agencies that regulate various aspects of their businesses, including rates and charges, service regulations, retail service territories, sales of securities, asset acquisitions and sales, accounting policies and practices, and the operation of fossil-fuel, nuclear, hydroelectric, solar, and biomass generating facilities, as well as transmission and distribution facilities. For example, the rates charged to wholesale customers by the traditional operating companies and by Southern Power Company must be approved by the FERC. These wholesale rates could be affected absent the ability to conduct business pursuant to FERC market-based rate authority. Additionally, the respective state PSCs must approve the traditional operating companies' requested rates for retail customers. While the retail rates of the traditional operating companies are designed to provide for the full recovery of costs (including a reasonable return on invested capital), there can be no assurance that a state PSC, in a future rate proceeding, will not attempt to alter the timing or amount of certain costs for which recovery is sought or to modify the current authorized rate of return.

Southern Company and its subsidiaries believe the necessary permits, approvals, and certificates have been obtained for their respective existing operations and that their respective businesses are conducted in accordance with applicable laws; however, the impact of any future revision or changes in interpretations of existing regulations or the adoption of new laws and regulations applicable to Southern Company or any of its subsidiaries cannot now be predicted. Changes in regulation or the imposition of additional regulations could influence the operating environment of Southern Company and its subsidiaries and may result in substantial costs.

The Southern Company system's costs of compliance with environmental laws are significant. The costs of compliance with current and future environmental laws, including laws and regulations designed to address air quality, water, coal combustion residuals, global climate change, renewable energy standards, and other matters and the incurrence of environmental liabilities could negatively impact the net income, cash flows, and financial condition of Southern Company, the traditional operating companies, and/or Southern Power.

The Southern Company system is subject to extensive federal, state, and local environmental requirements which, among other things, regulate air emissions, water usage and discharges, and the management of hazardous and solid waste in order to adequately protect the environment. Compliance with these environmental requirements requires the traditional operating companies and Southern Power to commit significant expenditures for installation of pollution control equipment, environmental monitoring, emissions fees, and permits at substantially all of their respective facilities. These expenditures are significant and Southern Company, the traditional operating companies, and Southern Power expect that they will continue to be significant in the future. Through 2013, the traditional operating companies had invested approximately $9.4 billion in environmental capital retrofit projects to comply with these requirements. The EPA has adopted and is in the process of implementing regulations governing the emission of nitrogen oxide, sulfur dioxide, fine particulate matter, mercury, and other air pollutants under the Clean Air Act through the national ambient air quality standards, CAIR, the MATS rule, and other air quality regulations and is in the process of considering additional revisions. In addition, the EPA has proposed additional regulations governing cooling water intake structures and has proposed revisions to the effluent guidelines for steam electric generating plants under the Clean Water Act. The EPA is also evaluating whether additional regulation of coal combustion residuals (including coal ash and gypsum) is merited under federal solid and hazardous waste laws.

Existing environmental laws and regulations may be revised or new laws and regulations related to air quality, water, coal combustion residuals, global climate change, or other environmental and health concerns may be adopted or become applicable to the traditional operating companies and/or Southern Power.

In addition, the EPA currently regulates emissions of carbon dioxide (CO_2) and other greenhouse gases under the Prevention of Significant Deterioration preconstruction permit program and the Title V operating permit program of the Clean Air Act, which both apply to power plants and other commercial and industrial facilities. On January 8, 2014, the EPA published re-proposed regulations to establish standards of performance for greenhouse gas emissions from new fossil fuel steam electric generating units and is expected to propose standards of performance for modified, reconstructed, and existing units during 2014.

The Southern Company system's ultimate environmental compliance strategy, including potential unit retirement and replacement decisions, and future environmental capital expenditures will be affected by the final requirements of new or revised environmental regulations ; the 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, and adding or changing fuel sources for certain existing units. Additionally, if Southern Company, any traditional operating company, or Southern Power fails to comply with environmental laws and regulations, even if caused by factors beyond its control, that failure may result in the assessment of civil or criminal penalties and fines. The EPA has filed civil actions against Alabama Power and Georgia Power and issued notices of violation to Gulf Power and Mississippi Power alleging violations of the new source review provisions of the Clean Air Act. An adverse outcome in any of these matters could require substantial capital expenditures that cannot be determined at this time and could possibly require payment of substantial penalties.

Compliance costs related to federal and state environmental statutes and regulations could affect earnings if such costs cannot continue to be fully recovered on a timely basis. Environmental compliance spending over the next several years may differ materially from the amounts estimated. The timing, specific requirements, and estimated costs could change as environmental statutes and regulations are adopted or modified. Such expenditures could affect unit retirement and replacement decisions and results of operations, cash flows, and financial condition if such costs are not recovered through regulated rates or long-term wholesale agreements for the traditional operating companies or market-based rates for Southern Power. 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.

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 increased generally throughout the U.S. In particular, personal injury, property damage, and other claims for damages alleged to have been caused by CO_2 and other emissions, coal combustion residuals, and alleged exposure to hazardous materials, and/or requests for injunctive relief in connection with such matters, have become more frequent.

The ultimate cost impact of proposed and final legislation and regulations and litigation are likely to result in significant and additional costs and could result in additional operating restrictions.

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

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

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

The FERC rules related to transmission are intended to spur the development of new transmission infrastructure to promote and encourage the integration of renewable sources of supply as well as facilitate competition in the wholesale market by providing more choices to wholesale power customers. In addition to the impacts on transactions contemplating physical delivery of energy, financial laws and regulations also impact power hedging and trading based on futures contracts and derivatives that are traded on various commodities exchanges as well as over-the-counter. Finally, technology changes in the power and fuel industries continue to create significant impacts to wholesale transaction cost structures. Southern Company, the traditional operating companies, and Southern Power cannot predict the impact of these and other such developments, nor can they predict the effect of changes in levels of wholesale supply and demand, which are typically driven by factors beyond their control. The financial condition, net income, and cash flows of Southern Company, the traditional operating companies, and Southern Power could be adversely affected by these and other changes.

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

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

OPERATIONAL RISKS

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

The financial performance of Southern Company and its subsidiaries depends on the successful operation of its subsidiaries' electric generating, transmission, and distribution facilities. Operating these facilities involves many risks, including:

- operator error or failure of equipment or processes, particularly with older generating facilities;

- operating limitations that may be imposed by environmental or other regulatory requirements;

- labor disputes;

- terrorist attacks;

- fuel or material supply interruptions;

- compliance with mandatory reliability standards, including mandatory cyber security standards;

- implementation of technologies with which the Southern Company system is developing experience;

- information technology system failure;

- cyber intrusion; and
- catastrophic events such as fires, earthquakes, explosions, floods, droughts, hurricanes, pandemic health events such as influenzas, or other similar occurrences.

A decrease or elimination of revenues from the electric generation, transmission, or distribution facilities or an increase in the cost of operating the facilities would reduce the net income and cash flows and could adversely impact the financial condition of the affected traditional operating company or Southern Power and of Southern Company. In addition, an investment in a subsidiary with such generation, transmission, or distribution facilities could be adversely impacted.

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

Alabama Power owns, and contracts for the operation of, two nuclear units and Georgia Power holds undivided interests in, and contracts for the operation of, four existing nuclear units. The six existing units are operated by Southern Nuclear and represent approximately 3,680 MWs, or 8.1%, of the Southern Company system's generation capacity as of December 31, 2013. In addition, Southern Nuclear, on behalf of Georgia Power and the other co-owners, is overseeing the construction of Plant Vogtle Units 3 and 4. Due solely to the increase in nuclear generating capacity, the below risks are expected to increase incrementally once Plant Vogtle Units 3 and 4 are operational. Nuclear facilities are subject to environmental, health, and financial risks such as:

- the potential harmful effects on the environment and human health resulting from a release of radioactive materials in connection with the operation of nuclear facilities and the storage, handling, and disposal of spent nuclear fuel;
- uncertainties with respect to the on-site storage of and the ability to dispose of spent nuclear fuel;
- uncertainties with respect to the technological and financial aspects of decommissioning nuclear plants at the end of licensed lives and the ability to maintain and anticipate adequate reserves for decommissioning;
- limitations on the amounts and types of insurance commercially available to cover losses that might arise in connection with the nuclear operations of Alabama Power and Georgia Power or those of other commercial nuclear facility owners in the United States;
- potential liabilities arising out of the operation of these facilities;
- significant capital expenditures relating to maintenance, operation, security, and repair of these facilities, including repairs and upgrades required by the NRC;
- the threat of a possible terrorist attack, including a potential cyber security attack; and
- the potential impact of a natural disaster.

Alabama Power and Georgia Power maintain decommissioning trusts and external insurance coverage, including statutorily required nuclear incident insurance, to minimize the potential financial exposure to these risks; however, it is possible that damages could exceed the amount of insurance coverage.

The NRC has broad authority under federal law to impose licensing and safety-related requirements for the operation of nuclear generation facilities. In the event of non-compliance with NRC licensing and safety-related requirements, the NRC has the authority to impose fines and/or shut down any unit, depending upon its assessment of the severity of the situation, until compliance is achieved. As a result of the major earthquake and tsunami that struck Japan in March 2011 and caused substantial damage to the nuclear generating units at the Fukushima Daiichi generating plant, the NRC is performing additional operational and safety reviews of nuclear facilities in the U.S., which could potentially impact future operations and capital requirements. The final form and the resulting impact of any changes to safety requirements for nuclear reactors will be dependent on further review and action by the NRC and cannot be determined at this time. NRC orders or regulations related to increased security measures and any future safety requirements promulgated by the NRC could require Alabama Power and Georgia Power to make substantial operating and capital expenditures at their nuclear plants. In addition, although Alabama Power, Georgia Power, and

Southern Company have no reason to anticipate a serious nuclear incident at the Southern Company system nuclear plants, if an incident did occur, it could result in substantial costs to Alabama Power or Georgia Power and Southern Company. A major incident at a nuclear facility anywhere in the world could cause the NRC to limit, prohibit, or require significant changes to the operation or licensing of any domestic nuclear unit that could result in substantial costs. Moreover, a major incident at any nuclear facility in the United States could require Alabama Power and Georgia Power to make material contributory payments.

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

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

The traditional operating companies and Southern Power face the risk of physical and cyber attacks, both threatened and actual, against their respective generation facilities, the transmission and distribution infrastructure used to transport power, and their information technology systems and network infrastructure, which could negatively impact the ability of the traditional operating companies or Southern Power to generate, transport, and deliver power, or otherwise operate their respective facilities in the most efficient manner or at all.

The traditional operating companies and Southern Power operate in a highly regulated industry that requires the continued operation of sophisticated information technology systems and network infrastructure, which are part of an interconnected regional grid. In addition, in the ordinary course of business, the traditional operating companies and Southern Power collect and retain sensitive information including personal identification information about customers and employees and other confidential information. The traditional operating companies and Southern Power face on-going threats to their assets. Despite the implementation of robust security measures, all assets are potentially vulnerable to disability, failures, or unauthorized access due to human error or physical or cyber attacks. If the traditional operating companies' or Southern Power's assets were to fail, be physically damaged, or be breached and were not recovered in a timely way, the traditional operating companies or Southern Power may be unable to fulfill critical business functions, and sensitive and other data could be compromised. The theft, damage, or improper disclosure of sensitive electronic data may also subject the applicable traditional operating company or Southern Power to penalties and claims from third parties.

These events could negatively affect the financial results of Southern Company, the traditional operating companies, or Southern Power through lost revenues, costs to recover and repair damage, and costs associated with governmental actions in response to such attacks.

The traditional operating companies and Southern Power may not be able to obtain adequate fuel supplies, which could limit their ability to operate their facilities.

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

The traditional operating companies are dependent on coal for a portion of their electric generating capacity. Each traditional operating company has coal supply contracts in place; however, there can be no assurance that the counterparties to these agreements will fulfill their obligations to supply coal to the traditional operating companies. The suppliers under these agreements may experience financial or technical problems which inhibit their ability to fulfill their obligations to the traditional operating companies. In addition, the suppliers under these agreements may not be required to supply coal to the traditional operating companies under certain circumstances, such as in the event of a natural disaster. If the traditional operating companies are unable to obtain their coal requirements under these contracts, the traditional operating companies may be required to purchase their coal requirements at higher prices, which may not be fully recoverable through rates.

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

Natural gas supplies can be subject to disruption in the event production or distribution is curtailed, such as in the event of a hurricane or a pipeline failure. The availability of shale gas and potential regulations affecting its accessibility may have a material impact on the supply and cost of natural gas.

In addition, world market conditions for fuels can impact the cost and availability of natural gas, coal, and uranium.

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

Most of Southern Power's generating capacity has been sold to purchasers under PPAs. In addition, the traditional operating companies enter into PPAs with non-affiliated parties. Revenues are dependent on the continued performance by the purchasers of their obligations under these PPAs. Even though Southern Power and the traditional operating companies have a rigorous credit evaluation process and contractual protections, the failure of one of the purchasers to perform its obligations could have a negative impact on the net income and cash flows of the affected traditional operating company or Southern Power and of Southern Company. Although these credit evaluations and contractual protections take into account the possibility of default by a purchaser, actual exposure to a default by a purchaser may be greater than predicted. Additionally, neither Southern Power nor any traditional operating company can predict whether the PPAs will be renewed at the end of their respective terms or on what terms any renewals may be made. If a PPA is not renewed, a replacement PPA cannot be assured.

Changes in technology may make Southern Company's electric generating facilities owned by the traditional operating companies and Southern Power less competitive.

A key element of the business models of Southern Company, the traditional operating companies, and Southern Power is that generating power at central station power plants achieves economies of scale and produces power at a competitive cost. There are distributed generation technologies that produce power, including fuel cells, microturbines, wind turbines, and solar cells. Advances in technology could reduce the cost of alternative methods of producing power to a level that is competitive with that of most central station power electric production or result in smaller-scale, more fuel efficient, and/or more cost effective distributed generation. Broader use of distributed generation by retail electric customers may also result from customers’ changing perceptions of the merits of utilizing existing generation technology or tax or other economic incentives. Additionally, there can be no assurance that a state PSC or legislature will not attempt to modify certain aspects of the traditional operating companies’ business as a result of these advances in technology. If these technologies became cost competitive and achieved sufficient scale, the market share of the traditional operating companies and Southern Power could be eroded, and the value of their respective electric generating facilities could be reduced. It is also possible that rapid advances in central station power generation technology could reduce the value of the current electric generating facilities owned by the traditional operating companies and Southern Power. Changes in technology could also alter the channels through which electric customers buy or utilize power, which could reduce the revenues or increase the expenses of Southern Company, the traditional operating companies, or Southern Power. If state PSCs fail to adjust rates to reflect the impact of any changes in loads, increasing self-generation, and the growth of distributed generation, the financial condition, results of operations, and cash flows of Southern Company and the traditional operating companies could be materially adversely affected.

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

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

These transactions are intended to, but may not, result in the generation of cash or income, the realization of savings, the creation of efficiencies, or the reduction of risk. These transactions may also affect the liquidity, results of operations, and financial condition of Southern Company and its subsidiaries.
These transactions also involve risks, and Southern Company and its subsidiaries cannot ensure that:

- any acquisitions would result in an increase in income or provide an adequate return of capital or other anticipated benefits;
- any acquisitions would be successfully integrated into the acquiring company's operations and internal controls;

- the due diligence conducted prior to an acquisition would uncover situations that could result in financial or legal exposure or that the acquiring company will appropriately quantify the exposure from known risks;
- any disposition would not result in decreased earnings, revenue, or cash flow;
- use of cash for acquisitions would not adversely affect cash available for capital expenditures and other uses; or
- any dispositions, investments, or acquisitions would not have a material adverse effect on the liquidity, results of operations, or financial condition of Southern Company or its subsidiaries.

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

Events such as an aging workforce without appropriate replacements, mismatch of skill sets to future needs, or unavailability of contract resources may lead to operating challenges such as lack of resources, loss of knowledge, and a lengthy time period associated with skill development, especially with the workforce needs associated with Plant Vogtle Units 3 and 4 and Kemper IGCC construction. The Southern Company system's costs, including costs for contractors to replace employees, productivity costs, and safety costs, may rise. Failure to hire and adequately obtain replacement employees, including the ability to transfer significant internal historical knowledge and expertise to the new employees, or the future availability and cost of contract labor may adversely affect Southern Company and its subsidiaries' ability to manage and operate their businesses. If Southern Company and its subsidiaries, including the traditional operating companies, are unable to successfully attract and retain an appropriately qualified workforce, results of operations could be negatively impacted.

CONSTRUCTION RISKS

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

General

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

- shortages and inconsistent quality of equipment, materials, and labor;
- labor costs;
- varied productivity and production;

- work stoppages;
- contractor or supplier delay or non-performance under construction or other agreements or non-performance by other major participants in construction projects;
- delays in or failure to receive necessary permits, approvals, and other regulatory authorizations;
- delays associated with start-up activities, including major equipment failure, system integration, and operations, and/or unforeseen engineering problems;

- impacts of new and existing laws and regulations, including environmental laws and regulations;
- the outcome of legal challenges to regulatory approvals;
- failure to construct in accordance with licensing requirements;
- continued public and policymaker support for such projects;
- adverse weather conditions;
- other unforeseen engineering problems;
- changes in project design or scope;
- environmental and geological conditions;
- delays or increased costs to interconnect facilities to transmission grids; and
- unanticipated cost increases, including materials and labor, and increased financing costs as a result of changes in market interest rates or as a result of construction schedule delays.

In addition, with respect to the construction of Plant Vogtle Units 3 and 4 and the operation of existing nuclear units, a major incident at a nuclear facility anywhere in the world could cause the NRC to delay or prohibit construction of new nuclear units or require additional safety measures at new and existing units, including any which may be required as a result of the major earthquake and tsunami that struck Japan in March 2011 and caused substantial damage to the nuclear generating units at the Fukushima Daiichi generating plant, which could potentially impact future operations and capital requirements. The final form and the resulting impact of any changes to safety requirements for nuclear reactors will be dependent on further review and action by the NRC and cannot be determined at this time.

If a traditional operating company or Southern Power is unable to complete the development or construction of a facility or decides to delay or cancel construction of a facility, it may not be able to recover its investment in that facility and may incur substantial cancellation payments under equipment purchase orders or construction contracts. Even if a construction project is completed, the total costs may be higher than estimated and there is no assurance that the traditional operating company will be able to recover such expenditures through regulated rates. In addition, construction delays and contractor performance shortfalls can result in the loss of revenues and may, in turn, adversely affect the net income and financial position of a traditional operating company or Southern Power and of Southern Company.

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

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

The two largest construction projects currently underway in the Southern Company system are the construction of Plant Vogtle Units 3 and 4 and the Kemper IGCC.

Plant Vogtle Units 3 and 4 construction

Southern Nuclear, on behalf of Georgia Power and the other co-owners, is overseeing the construction of and will operate Plant Vogtle Units 3 and 4 (each, an approximately 1,100 MW AP1000 nuclear generating unit). Georgia Power owns 45.7% of the new units. The NRC certified the Westinghouse Electric Company LLC's Design Certification Document, as amended (DCD), for the AP1000 reactor design, effective December 30, 2011, and issued combined COLs in February 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 are expected as construction proceeds.
Georgia Power is required to file semi-annual Vogtle Construction Monitoring (VCM) reports with the Georgia PSC by February 28 and August 31 of each year. If the projected certified construction capital costs to be borne by Georgia Power increase by 5% 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. Accordingly, Georgia Power's eighth VCM report 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 fourth quarter 2017 and fourth quarter 2018 for Plant Vogtle Units 3 and 4, respectively.

On September 3, 2013, the Georgia PSC approved a stipulation entered into by Georgia Power and the Georgia PSC staff to waive the requirement to amend the Plant Vogtle Units 3 and 4 certificate, until the commercial operation date of Plant Vogtle Unit 3, or earlier if deemed appropriate by the Georgia PSC and Georgia Power. In accordance with the Georgia Integrated Resource Planning Act, any costs incurred by Georgia Power in excess of the certified amount will not be included in rate base, unless shown to be reasonable and prudent. In addition, financing costs on any excess construction-related costs potentially would be subject to recovery for allowance for funds used during construction instead of the Nuclear Construction Cost Recovery tariff.

Georgia Power, OPC, MEAG Power, and Dalton (collectively, the Owners) and Westinghouse Electric Company LLC (Westinghouse) and Stone & Webster, Inc. (Stone & Webster) (collectively, the Contractor) are involved in litigation regarding the costs associated with design changes to the DCD and delays in the timing of approval of the DCD and issuance of the COLs, including the assertion by the Contractor that the Owners are responsible for these costs and that the Contractor is entitled to further schedule extensions. The portion of the additional costs claimed by the Contractor that would be attributable to Georgia Power (based on Georgia Power's ownership interest) with respect to these issues is approximately $425 million (in 2008 dollars). Georgia Power has not agreed with either the proposed cost or schedule adjustments or that the Owners have any responsibility for costs related to these issues. While litigation has commenced and Georgia Power intends to vigorously defend its positions, Georgia Power also expects negotiations with the Contractor to continue with respect to costs and schedule during which negotiations the parties may reach a mutually acceptable compromise of their positions.

Processes are in place that are designed to assure compliance with the requirements specified in the DCD and 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 licensed-based compliance issues are expected to 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 Owners, the Contractor, or both.

As construction continues, the risk remains that additional challenges in the fabrication, assembly, delivery, and installation of 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. Additional claims by the Contractor or Georgia Power (on behalf of the Owners) are also likely to arise throughout construction. These claims may be resolved through formal and informal dispute resolution procedures under the engineering, procurement, and construction agreement for Plant Vogtle Units 3 and 4, but also may be resolved through litigation.

Kemper IGCC construction

In April 2012, the Mississippi PSC issued a detailed order confirming the CPCN originally approved by the Mississippi PSC in 2010 authorizing the acquisition, construction, and operation of the Kemper IGCC (2012 MPSC CPCN Order), which the Sierra Club appealed to the Chancery Court of Harrison County, Mississippi (Chancery Court). In December 2012, the Chancery Court affirmed the 2012 MPSC CPCN Order. On January 8, 2013, the Sierra Club filed an appeal of the Chancery

Court's ruling with the Mississippi Supreme Court. The ultimate outcome of the CPCN challenge cannot be determined at this time.

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 project by the U.S. Department of Energy 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 allowance for funds used during construction (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. Exceptions to the $2.88 billion cost cap include 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 the ratepayers, relative to the original proposal for the CPCN) (Cost Cap Exceptions), as contemplated in the settlement agreement between Mississippi Power and the Mississippi PSC entered into on January 24, 2013 (Settlement Agreement) and the 2012 MPSC CPCN Order. Recovery of the Cost Cap Exception amounts remains subject to review and approval by the Mississippi PSC. The Kemper IGCC was originally scheduled to be placed in service in May 2014 and is currently scheduled to be placed in service in the fourth quarter 2014.

Mississippi Power does not intend to seek any rate recovery or joint owner contributions for any related costs that exceed the $2.88 billion cost cap, excluding the Cost Cap Exceptions and net of the DOE Grants. Through December 31, 2013, Southern Company and Mississippi Power have recorded pre-tax charges to income for revisions to the cost estimate of $1.2 billion ($729 million after tax). The revised cost estimates through December 31, 2013 reflect increased labor costs, piping and other material costs, start-up costs, decreases in construction labor productivity, the change in the in-service date, and an increase in the contingency for risks associated with start-up activities.

Mississippi Power could experience further construction cost increases and/or schedule extensions with respect to the Kemper IGCC as a result of 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, or non-performance under construction or other agreements. Furthermore, Mississippi Power could also experience further schedule extensions associated with start-up activities for this "first-of-its-kind" technology, including major equipment failure, system integration, and operations, and/or unforeseen engineering problems, which would result in further cost increases and could result in the loss of certain tax benefits related to bonus depreciation. 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 will be reflected in Southern Company’s and Mississippi Power’s statements of income and these changes could be material.

On January 24, 2013, Mississippi Power entered into the Settlement Agreement with the Mississippi PSC that, among other things, establishes the process for resolving matters regarding cost recovery related to the Kemper IGCC. Under the 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. The Settlement Agreement also allows Mississippi Power to secure alternate financing for costs that are not otherwise recovered in any Mississippi PSC rate proceedings contemplated by the Settlement Agreement.

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 on February 26, 2013. Mississippi Power intends to securitize (1) prudently-incurred costs in excess of the certificated cost estimate and up to the $2.88 billion cost cap, net of the DOE Grants and excluding the Cost Cap Exceptions, (2) accrued AFUDC, and (3) other prudently-incurred costs as approved by the Mississippi PSC. The rate recovery necessary to recover the annual costs of securitization is expected to be filed and become effective after the Kemper IGCC is placed in service and following completion of the Mississippi PSC's final prudence review of costs for the Kemper IGCC.

The Settlement Agreement provides that Mississippi Power may terminate the Settlement Agreement if certain conditions are not met, if Mississippi Power is unable to secure alternate financing for any prudently-incurred Kemper IGCC costs not otherwise recovered in any Mississippi PSC rate proceeding contemplated by the Settlement Agreement, or if the Mississippi PSC fails to comply with the requirements of the Settlement Agreement. Mississippi Power continues to work with the Mississippi PSC and the Mississippi Public Utilities Staff to implement the procedural schedules set forth in the Settlement Agreement and additional variations to the schedule are likely.

Consistent with the Settlement Agreement, on March 5, 2013, the Mississippi PSC issued an order (2013 MPSC Rate Order), approving retail rate increases of 15% effective March 19, 2013 and 3% effective January 1, 2014, which collectively are designed to collect $156 million annually beginning in 2014. Amounts collected through these rates are being recorded as a regulatory liability to be used to mitigate customer rate impacts after the Kemper IGCC is placed in service. On March 21, 2013, a legal challenge to the 2013 MPSC Rate Order was filed by Thomas A. Blanton with the Mississippi Supreme Court, which remains pending against Mississippi Power and the Mississippi PSC.

Also consistent with the Settlement Agreement, on February 26, 2013, Mississippi Power filed with the Mississippi PSC a rate recovery plan for the Kemper IGCC for the first seven years of its operation, along with a proposed revenue requirement under such plan for 2014 through 2020 (Seven-Year Rate Plan). On March 22, 2013, Mississippi Power, in compliance with the 2013 MPSC Rate Order, filed a revision to the Seven-Year Rate Plan with the Mississippi PSC for the Kemper IGCC for cost recovery through 2020, which is still under review by the Mississippi PSC. The revenue requirements set forth in the Seven-Year Rate Plan assume the sale of a 15% undivided interest in the Kemper IGCC to SMEPA and utilization of bonus depreciation as provided by the American Taxpayer Relief Act of 2012, which currently requires that the Kemper IGCC be placed in service in 2014.

In 2014, Mississippi Power plans to amend the Seven-Year Rate Plan to reflect changes including the revised in-service date, the change in expected benefits relating to tax credits, various other revenue requirement items, and other tax matters, which include ensuring compliance with the normalization requirements of the Internal Revenue Code. The impact of these revisions for the average annual retail revenue requirement is estimated to be approximately $35 million through 2020. The amendment to the Seven-Year Rate Plan is also expected to reflect rate mitigation options identified by Mississippi Power that, if approved by the Mississippi PSC, would result in no change to the total customer rate impacts contemplated in the original Seven-Year Rate Plan.

Further cost increases and/or schedule extensions with respect to the Kemper IGCC could have an adverse impact on the Seven-Year Rate Plan, such as the inability to recover items considered as Cost Cap Exceptions, potential costs subject to securitization financing in excess of $1.0 billion, and the loss of certain tax benefits related to bonus depreciation. While the Kemper IGCC is scheduled to be placed in service in the fourth quarter 2014, any schedule extension beyond 2014 would result in the loss of tax benefits related to bonus depreciation. The estimated value of the bonus depreciation tax benefits to retail customers is approximately $200 million. Loss of these tax benefits would require further adjustment to the Seven-Year Rate Plan and approval by the Mississippi PSC to ensure compliance with the normalization requirements of the Internal Revenue Code. In the event that the Mississippi PSC does not approve or Mississippi Power withdraws the Seven-Year Rate Plan, Mississippi Power would seek rate recovery through an alternate means, which could include a traditional rate case.

The Mississippi PSC’s prudence review of Kemper IGCC costs incurred through March 31, 2013, as provided for in the Settlement Agreement, is expected to occur in the second quarter 2014. A final review of all costs incurred after March 31, 2013 is expected to be completed within six months of the Kemper IGCC’s in-service date. Furthermore, regardless of any prudence determinations made during the construction and start-up period, the Mississippi PSC has the right to make a final prudence determination after the Kemper IGCC has been placed in service.

The ultimate outcome of these matters, including the resolution of legal challenges, determinations of prudency, and the specific manner of recovery of prudently-incurred costs, is subject to further regulatory actions and cannot be determined at this time.

FINANCIAL, ECONOMIC, AND MARKET RISKS

The generation operations and energy marketing operations of Southern Company, the traditional operating companies, and Southern Power are subject to risks, many of which are beyond their control, including changes in power prices and fuel costs, that may reduce Southern Company's, the traditional operating companies', and/or Southern Power's revenues and increase costs.

The generation operations and energy marketing operations of the Southern Company system are subject to changes in power prices and fuel costs, which could increase the cost of producing power or decrease the amount received from the sale of power. The market prices for these commodities may fluctuate significantly over relatively short periods of time. The Southern Company system attempts to mitigate risks associated with fluctuating fuel costs by passing these costs on to customers through the traditional operating companies' fuel cost recovery clauses or through PPAs. Among the factors that could influence power prices and fuel costs are:

- prevailing market prices for coal, natural gas, uranium, fuel oil, biomass, and other fuels used in the generation facilities of the traditional operating companies and Southern Power, including associated transportation costs, and supplies of such commodities;

- demand for energy and the extent of additional supplies of energy available from current or new competitors;
- liquidity in the general wholesale electricity market;
- weather conditions impacting demand for electricity;
- seasonality;
- transmission or transportation constraints or inefficiencies;
- availability of competitively priced alternative energy sources;
- forced or unscheduled plant outages for the Southern Company system, its competitors, or third party providers;
- the financial condition of market participants;
- the economy in the service territory, the nation, and worldwide, including the impact of economic conditions on demand for electricity and the demand for fuels;
- natural disasters, wars, embargos, acts of terrorism, and other catastrophic events; and
- federal, state, and foreign energy and environmental regulation and legislation.

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

Historically, the traditional operating companies from time to time have experienced underrecovered fuel cost balances and deficits in their storm cost recovery reserve balances and may experience such balances and deficits in the future. While the traditional operating companies are generally authorized to recover underrecovered fuel costs through fuel cost recovery clauses and storm recovery costs through special rate provisions administered by the respective PSCs, recovery may be denied if costs are deemed to be imprudently incurred, and delays in the authorization of such recovery could negatively impact the cash flows of the affected traditional operating company and Southern Company.

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

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

Outside of economic disruptions, changes in customer behaviors in response to changing conditions and preferences or changes in the adoption of technologies could affect the relationship of economic activity to the consumption of electricity. On the customer behavior side, federal and state programs exist to influence how customers use energy, and several of the traditional operating companies have PSC mandates to promote energy efficiency. The adoption of technology by customers can have both positive and negative impacts on sales. Many new technologies utilize less energy than in the past. However, new electric technologies such as electric vehicles can create additional demand. The Southern Company system's planning processes incorporate estimates of the impacts of changes in customer behavior, state and federal programs, PSC mandates, and technology, but upside and downside risks remain.

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

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

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

In addition, volatile or significant weather events could result in substantial damage to the transmission and distribution lines of the traditional operating companies and the generating facilities of the traditional operating companies and Southern Power. The traditional operating companies and Southern Power have significant investments in the Atlantic and Gulf Coast regions which could be subject to major storm activity. Further, severe drought conditions can reduce the availability of water and restrict or prevent the operation of certain generating facilities.

Each traditional operating company maintains a reserve for property damage to cover the cost of damages from weather events to its transmission and distribution lines and the cost of uninsured damages to its generating facilities and other property. In the event a traditional operating company experiences any of these weather events or any natural disaster or other catastrophic event, recovery of costs in excess of reserves and insurance coverage is subject to the approval of its state PSC. While the traditional operating companies generally are entitled to recover prudently-incurred costs incurred in connection with such an event, any denial by the applicable state PSC or delay in recovery of any portion of such costs could have a material negative impact on a traditional operating company's and Southern Company's results of operations, financial condition, and liquidity.

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

Southern Company may be unable to meet its ongoing and future financial obligations and to pay dividends on its common stock if its subsidiaries are unable to pay upstream dividends or repay funds to Southern Company.

Southern Company is a holding company and, as such, Southern Company has no operations of its own. Substantially all of Southern Company's consolidated assets are held by subsidiaries. Southern Company's ability to meet its financial obligations and to pay dividends on its common stock is primarily dependent on the net income and cash flows of its subsidiaries and their ability to pay upstream dividends or to repay funds to Southern Company. Prior to funding Southern Company, Southern Company's subsidiaries have regulatory restrictions and financial obligations that must be satisfied, including among others, debt service and preferred and preference stock dividends. Southern Company's subsidiaries are separate legal entities and have no obligation to provide Southern Company with funds.

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

There are a number of factors that rating agencies evaluate to arrive at credit ratings for Southern Company, the traditional operating companies, and Southern Power Company, including capital structure, regulatory environment, the ability to cover liquidity requirements, and other commitments for capital. Southern Company, the traditional operating companies, and Southern Power Company could experience a downgrade in their ratings if any rating agency concludes that the level of business or financial risk of the industry or Southern Company, the traditional operating companies, or Southern Power Company has deteriorated. Changes in ratings methodologies by the agencies could also have a negative impact on credit ratings. If one or more rating agencies downgrade Southern Company, the traditional operating companies, or Southern Power

Company, borrowing costs would increase, the pool of investors and funding sources would likely decrease, and, particularly for any downgrade to below investment grade, significant collateral requirements may be triggered in a number of contracts.

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

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

Demand for power could decrease or fail to grow at expected rates, resulting in stagnant or reduced revenues, limited growth opportunities, and potentially stranded generation assets.

Southern Company, the traditional operating companies, and Southern Power each engage in a long-term planning process to determine the optimal mix and timing of new generation assets required to serve future load obligations. This planning process must look many years into the future in order to accommodate the long lead times associated with the permitting and construction of new generation facilities. Inherent risk exists in predicting demand this far into the future as these future loads are dependent on many uncertain factors, including regional economic conditions, customer usage patterns, efficiency programs, and customer technology adoption. Because regulators may not permit the traditional operating companies to adjust rates to recover the costs of new generation assets while such assets are being constructed, the traditional operating companies may not be able to fully recover these costs or may have exposure to regulatory lag associated with the time between the incurrence of costs of additional capacity and the traditional operating companies' recovery in customers' rates. Under Southern Power's model of selling capacity and energy at negotiated market-based rates under long-term PPAs, Southern Power might not be able to fully execute its business plan if market prices drop below original forecasts. Southern Power and/or the traditional operating companies may not be able to extend existing PPAs or to find new buyers for existing generation assets as existing PPAs expire, or it may be forced to market these assets at prices lower than originally intended. These situations could have negative impacts on net income and cash flows for the affected traditional operating company or Southern Power and for Southern Company.

Demand for power could exceed supply capacity, resulting in increased costs for purchasing capacity in the open market or building additional generation and transmission facilities.

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

Energy conservation and energy price increases could negatively impact financial results.

Customers could voluntarily reduce their consumption of electricity in response to decreases in their disposable income, increases in energy price, or individual conservation efforts, which could negatively impact the results of operations of Southern Company, the traditional operating companies, and Southern Power. In addition, a number of regulatory and legislative bodies have proposed or introduced requirements and/or incentives to reduce energy consumption by certain dates. Conservation programs could impact the financial results of Southern Company, the traditional operating companies, and Southern Power in different ways. For example, if any traditional operating company is required to invest in conservation measures that result in reduced sales from effective conservation, regulatory lag in adjusting rates for the impact of these measures could have a negative financial impact on such traditional operating company and Southern Company.

Certain of the traditional operating companies actively promote energy conservation programs, which have been approved by their respective state PSCs. For certain of such traditional operating companies, regulatory mechanisms have been established that provide for the recovery of costs related to such programs and lost revenues as a result of such programs. However, to the extent conservation results in reduced energy demand or significantly slows the growth in demand beyond what is anticipated, the value of generation assets of the traditional operating companies and/or Southern Power and other unregulated business activities could be adversely impacted and the traditional operating companies could be negatively impacted depending on the regulatory treatment of the associated impacts. In addition, the failure of those traditional operating companies who actively promote energy conservation programs to achieve the energy conservation targets established by their respective state PSCs could negatively impact such traditional operating company's ability to recover costs and lost revenues as a result of such progress and ability to receive certain benefits related to such programs.

Southern Company, the traditional operating companies, and Southern Power are unable to determine what impact, if any, conservation and increases in energy prices will have on their respective financial condition or results of operations.

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

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

- an economic downturn or uncertainty;
- bankruptcy or financial distress at an unrelated energy company, financial institution, or sovereign entity;
- capital markets volatility and disruption, either nationally or internationally;

- changes in tax policy such as dividend tax rates;

- market prices for electricity and gas;

- terrorist attacks or threatened attacks on Southern Company's facilities or unrelated energy companies' facilities;

- war or threat of war; or

- the overall health of the utility and financial institution industries.

In addition, Georgia Power’s ability to make future borrowings through its term loan credit facility with the Federal Financing Bank is subject to the satisfaction of customary conditions, as well as certification of compliance with the requirements of the loan guarantee program under Title XVII of the Energy Policy Act of 2005, including accuracy of project-related representations and warranties, delivery of updated project-related information and evidence of compliance with the prevailing wage requirements of the Davis-Bacon Act of 1931, as amended, compliance with the Cargo Preference Act of 1954, and certification from the DOE's consulting engineer that proceeds of the advances are used to reimburse certain costs of construction relating to Plant Vogtle Units 3 and 4 that are eligible for financing under the Title XVII Loan Guarantee Program.

Market performance and other changes may decrease the value of benefit plans and nuclear decommissioning trust assets or may increase plan costs, which then could require significant additional funding.

The performance of the capital markets affects the values of the assets held in trust under Southern Company's pension and postretirement benefit plans and the assets held in trust to satisfy obligations to decommission Alabama Power's and Georgia Power's nuclear plants. The Southern Company system has significant obligations related to pension and postretirement benefit plans. Alabama Power and Georgia Power each hold significant assets in the nuclear decommissioning trusts. These assets are subject to market fluctuations and will yield uncertain returns, which may fall below projected return rates. A decline in the market value of these assets may increase the funding requirements relating to benefit plan liabilities of the Southern Company system and Alabama Power's and Georgia Power's nuclear decommissioning obligations. Additionally, changes in interest rates affect the liabilities under pension and postretirement benefit plans of the Southern Company system; as interest rates decrease, the liabilities increase, potentially requiring additional funding. Further, changes in demographics, including an increased number of retirements or changes in life expectancy assumptions, may also increase the funding requirements of the obligations related to the pension benefit plans. Southern Company and its subsidiaries are also facing rising medical benefit costs, including the current costs for active and retired employees. It is possible that these costs may increase at a rate that is significantly higher than anticipated. If the Southern Company system is unable to successfully manage benefit plan assets and medical benefit costs and Alabama Power and Georgia Power are unable to successfully manage the nuclear decommissioning trust funds, results of operations and financial position could be negatively affected.

Southern Company may be unable to recover its investment in its leveraged leases if a lessee fails to profitably operate the leased assets.

Southern Company has several leveraged lease agreements, with terms ranging up to 45 years, which relate to international and domestic energy generation, distribution, and transportation assets. Southern Company receives federal income tax deductions for depreciation and amortization, as well as interest on long-term debt related to these investments. Southern Company reviews all important lease assumptions at least annually, or more frequently if events or changes in circumstances indicate that a change in assumptions has occurred or may occur. With respect to Southern Company's investments in leveraged leases, the recovery of its investment is dependent on the profitable operation of the leased assets by the respective lessees. A significant deterioration in the performance of the leased asset could result in the impairment of the related lease receivable.

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

The financial condition of some insurance companies, the threat of terrorism, and natural disasters, among other things, could have disruptive effects on insurance markets. The availability of insurance covering risks that Southern Company, the traditional operating companies, Southern Power, and their respective competitors typically insure against may decrease, and the insurance that Southern Company, the traditional operating companies, and Southern Power are able to obtain may have higher deductibles, higher premiums, and more restrictive policy terms. Further, while Southern Company, the traditional operating companies, and Southern Power maintain an amount of insurance protection that they consider adequate, there is no guarantee that the insurance policies selected by them will cover all of the potential exposures or the actual amount of loss incurred.

Any losses not covered by insurance could adversely affect the results of operations, cash flows, or financial condition of Southern Company, the traditional operating companies, or Southern Power.

Item 1B. UNRESOLVED STAFF COMMENTS.
None.

Table of Contents Index to Financial Statements

Item 2. PROPERTIES

Electric Properties

The traditional operating companies, Southern Power, and SEGCO, at December 31, 2013, owned and/or operated 33 hydroelectric generating stations, 32 fossil fuel generating stations, three nuclear generating stations, and 13 combined cycle/cogeneration stations, six solar facilities, one biomass facility, and one landfill gas facility. The amounts of capacity for each company are shown in the table below.

Generating Station	Location	Nameplate Capacity (1) (KWs)	
FOSSIL STEAM			
Gadsden	Gadsden, AL	120,000	
Gorgas	Jasper, AL	1,221,250	
Barry	Mobile, AL	1,525,000	
Greene County	Demopolis, AL	300,000	(2)
Gaston Unit 5	Wilsonville, AL	880,000	
Miller	Birmingham, AL	2,532,288	(3)
Alabama Power Total		6,578,538	
Bowen	Cartersville, GA	3,160,000	
Branch	Milledgeville, GA	1,220,700	(4)
Hammond	Rome, GA	800,000	
Kraft	Port Wentworth, GA	281,136	(4)
McIntosh	Effingham County, GA	163,117	(4)
McManus	Brunswick, GA	115,000	(4)
Mitchell	Albany, GA	125,000	(4)
Scherer	Macon, GA	750,924	(5)
Wansley	Carrollton, GA	925,550	(6)
Yates	Newnan, GA	1,250,000	(4)
Georgia Power Total		8,791,427	
Crist	Pensacola, FL	970,000	
Daniel	Pascagoula, MS	500,000	(7)
Lansing Smith	Panama City, FL	305,000	
Scholz	Chattahoochee, FL	80,000	(16)
Scherer Unit 3	Macon, GA	204,500	(5)
Gulf Power Total		2,059,500	
Daniel	Pascagoula, MS	500,000	(7)
Greene County	Demopolis, AL	200,000	(2)
Sweatt	Meridian, MS	80,000	
Watson	Gulfport, MS	1,012,000	
Mississippi Power Total		1,792,000	
Gaston Units 1-4	Wilsonville, AL		
SEGCO Total		1,000,000	(4)(8)
Total Fossil Steam		20,221,465	

Generating Station	Location	Nameplate Capacity (1)	
NUCLEAR STEAM			
Farley	Dothan, AL		
Alabama Power Total		1,720,000	
Hatch	Baxley, GA	899,612	(9)
Vogtle	Augusta, GA	1,060,240	(10)
Georgia Power Total		1,959,852	
Total Nuclear Steam		3,679,852	
COMBUSTION TURBINES			
Greene County	Demopolis, AL		
Alabama Power Total		720,000	
Boulevard	Savannah, GA	19,700	(4)
Intercession City	Intercession City, FL	47,667	(11)
Kraft	Port Wentworth, GA	22,000	
McDonough Unit 3	Atlanta, GA	78,800	
McIntosh Units 1 through 8	Effingham County, GA	640,000	
McManus	Brunswick, GA	481,700	
Mitchell	Albany, GA	78,800	
Robins	Warner Robins, GA	158,400	
Wansley	Carrollton, GA	26,322	(6)
Wilson	Augusta, GA	354,100	
Georgia Power Total		1,907,489	
Lansing Smith Unit A	Panama City, FL	39,400	
Pea Ridge Units 1 through 3	Pea Ridge, FL	15,000	
Gulf Power Total		54,400	
Chevron Cogenerating Station	Pascagoula, MS	147,292	(12)
Sweatt	Meridian, MS	39,400	
Watson	Gulfport, MS	39,360	
Mississippi Power Total		226,052	
Cleveland County	Cleveland County, NC	720,000	
Dahlberg	Jackson County, GA	756,000	
Oleander	Cocoa, FL	791,301	
Rowan	Salisbury, NC	455,250	
West Georgia	Thomaston, GA	668,800	
Southern Power Total		3,391,351	
Gaston (SEGCO)	Wilsonville, AL	19,680	(8)
Total Combustion Turbines		6,318,972	
COGENERATION			
Washington County	Washington County, AL	123,428	
GE Plastics Project	Burkeville, AL	104,800	
Theodore	Theodore, AL	236,418	
Total Cogeneration		464,646	

Generating Station	Location	Nameplate Capacity (1)	
COMBINED CYCLE			
Barry	Mobile, AL		
Alabama Power Total		1,070,424	
McIntosh Units 10&11	Effingham County, GA	1,318,920	
McDonough-Atkinson Units 4 through 6	Atlanta, GA	2,520,000	
Georgia Power Total		3,838,920	
Smith	Lynn Haven, FL		
Gulf Power Total		545,500	
Daniel	Pascagoula, MS		
Mississippi Power Total		1,070,424	
Franklin	Smiths, AL	1,857,820	
Harris	Autaugaville, AL	1,318,920	
Rowan	Salisbury, NC	530,550	
Stanton Unit A	Orlando, FL	428,649	(13)
Wansley	Carrollton, GA	1,073,000	
Southern Power Total		5,208,939	
Total Combined Cycle		11,734,207	
HYDROELECTRIC FACILITIES			
Bankhead	Holt, AL	53,985	
Bouldin	Wetumpka, AL	225,000	
Harris	Wedowee, AL	132,000	
Henry	Ohatchee, AL	72,900	
Holt	Holt, AL	46,944	
Jordan	Wetumpka, AL	100,000	
Lay	Clanton, AL	177,000	
Lewis Smith	Jasper, AL	157,500	
Logan Martin	Vincent, AL	135,000	
Martin	Dadeville, AL	182,000	
Mitchell	Verbena, AL	170,000	
Thurlow	Tallassee, AL	81,000	
Weiss	Leesburg, AL	87,750	
Yates	Tallassee, AL	47,000	
Alabama Power Total		1,668,079	
Bartletts Ferry	Columbus, GA	173,000	
Goat Rock	Columbus, GA	38,600	
Lloyd Shoals	Jackson, GA	14,400	
Morgan Falls	Atlanta, GA	16,800	
North Highlands	Columbus, GA	29,600	
Oliver Dam	Columbus, GA	60,000	
Rocky Mountain	Rome, GA	215,256	(14)
Sinclair Dam	Milledgeville, GA	45,000	
Tallulah Falls	Clayton, GA	72,000	
Terrora	Clayton, GA	16,000	
Tugalo	Clayton, GA	45,000	

Table of Contents Index to Financial Statements

Generating Station	Location	Nameplate Capacity (1)	
Wallace Dam	Eatonton, GA	321,300	
Yonah	Toccoa, GA	22,500	
6 Other Plants	Various Georgia Cities	18,080	
Georgia Power Total		1,087,536	
Total Hydroelectric Facilities		2,755,615	
RENEWABLE SOURCES:			
SOLAR FACILITIES			
Dalton	Dalton, GA		
Georgia Power Total		705	
Apex	North Las Vegas, NV	18,000	
Cimarron	Springer, NM	27,576	
Granville	Oxford, NC	2,250	
Spectrum	Clark County, NV	27,216	
Campo Verde	Imperial County, CA	132,678	
Southern Power Total		207,720	(15)
Total Solar		208,425	
LANDFILL GAS FACILITY			
Perdido	Escambia County, FL		
Gulf Power Total		3,200	
BIOMASS FACILITY			
Nacogdoches	Sacul, Texas		
Southern Power Total		115,500	
Total Generating Capacity		45,501,882	

Notes:

(1) See "Jointly-Owned Facilities" herein for additional information.
(2) Owned by Alabama Power and Mississippi Power as tenants in common in the proportions of 60% and 40%, respectively.
(3) Capacity shown is Alabama Power's portion (91.84%) of total plant capacity.
(4) Georgia Power's Plant Bowen Unit 6 (39,400 KWs) was retired on April 25, 2013. Georgia Power's Plant Boulevard Units 2 and 3 (39,400 KWs) were retired on July 17, 2013. Georgia Power's Plant Branch Unit 2 (319,000 KWs) was retired on September 30, 2013. See MANAGEMENT'S DISCUSSION AND ANALYSIS – FUTURE EARNINGS POTENTIAL – "PSC Matters – Georgia Power – Integrated Resource Plans" of Southern Company and MANAGEMENT'S DISCUSSION AND ANALYSIS – FUTURE EARNINGS POTENTIAL – "PSC Matters – Integrated Resource Plans" of Georgia Power in Item 7 herein. See also, Note 3 to the financial statements of Southern Company and Georgia Power under "Retail Regulatory Matters – Georgia Power – Integrated Resource Plans" and "Retail Regulatory Matters – Integrated Resource Plans," respectively, in Item 8 herein for information on plant retirements, fuel switching, and conversions.
(5) Capacity shown for Georgia Power is 8.4% of Units 1 and 2 and 75% of Unit 3. Capacity shown for Gulf Power is 25% of Unit 3.
(6) Capacity shown is Georgia Power's portion (53.5%) of total plant capacity.
(7) Represents 50% of the plant which is owned as tenants in common by Gulf Power and Mississippi Power.
(8) SEGCO is jointly-owned by Alabama Power and Georgia Power. See BUSINESS in Item 1 herein for additional information. See MANAGEMENT'S DISCUSSION AND ANALYSIS – FUTURE EARNINGS POTENTIAL – "PSC Matters – Georgia Power – Integrated Resource Plans" of Southern Company and MANAGEMENT'S DISCUSSION AND ANALYSIS – FUTURE EARNINGS POTENTIAL – "PSC Matters – Integrated Resource Plans" of Georgia Power in Item 7 herein. See also, Note 3 to the financial statements of Southern Company and Georgia Power under "Retail Regulatory Matters – Georgia Power – Integrated Resource Plans" and "Retail Regulatory Matters – Integrated Resource Plans," respectively, in Item 8 herein for information on fuel switching at Plant Gaston.
(9) Capacity shown is Georgia Power's portion (50.1%) of total plant capacity.
(10) Capacity shown is Georgia Power's portion (45.7%) of total plant capacity.
(11) Capacity shown represents 33 1/3% of total plant capacity. Georgia Power owns a 1/3 interest in the unit with 100% use of the unit from June through September. Duke Energy Florida operates the unit.
(12) Generation is dedicated to a single industrial customer.
(13) Capacity shown is Southern Power's portion (65%) of total plant capacity.
(14) Capacity shown is Georgia Power's portion (25.4%) of total plant capacity. OPC operates the plant.
(15) Capacity shown is Southern Power's portion (90%) of the total plant capacity.
(16) See MANAGEMENT'S DISCUSSION AND ANALYSIS – FUTURE EARNINGS POTENTIAL – "Environmental Matters" of Gulf Power in Item 7 herein for information on a scheduled plant retirement in 2015.

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

Mississippi Power owns a 79-mile length of 500-kilovolt transmission line which is leased to Entergy Gulf States Louisiana, LLC. The line, completed in 1984, extends from Plant Daniel to the Louisiana state line. Entergy Gulf States Louisiana, LLC is paying a use fee over a 40-year period covering all expenses and the amortization of the original $57 million cost of the line. At December 31, 2013, the unamortized portion of this cost was approximately $15.5 million.

In conjunction with the Kemper IGCC, Mississippi Power owns a lignite mine and equipment and has acquired and will continue to acquire mineral reserves located around the Kemper IGCC site in Kemper County. The mine, operated by North American Coal Corporation, started commercial operation on June 5, 2013. The estimated capital cost of the mine and equipment is approximately $233.1 million, of which $227.6 million has been incurred through December 31, 2013. See MANAGEMENT'S DISCUSSION AND ANALYSIS – FUTURE EARNINGS POTENTIAL – "Integrated Coal Gasification Combined Cycle – Lignite Mine and CO_2 Pipeline Facilities" of Mississippi Power in Item 7 herein and Note 3 to the financial statements of Southern Company and Mississippi Power under "Integrated Coal Gasification Combined Cycle – Lignite Mine and CO_2 Pipeline Facilities" in Item 8 herein for additional information on the lignite mine.

In 2013, the maximum demand on the traditional operating companies, Southern Power, and SEGCO was 33,557,000 KWs and occurred on June 13, 2013. The all-time maximum demand of 38,777,000 KWs on the traditional operating companies, Southern Power, and SEGCO occurred on August 22, 2007. These amounts exclude demand served by capacity retained by

Table of Contents Index to Financial Statements

MEAG Power, OPC, and SEPA. The reserve margin for the traditional operating companies, Southern Power, and SEGCO in 2013 was 21.5%. See SELECTED FINANCIAL DATA in Item 6 herein for additional information on peak demands for each registrant.

Jointly-Owned Facilities

Alabama Power, Georgia Power, and Southern Power have undivided interests in certain generating plants and other related facilities to or from non-affiliated parties. The percentages of ownership are as follows:

		Percentage Ownership										
	Total Capacity	Alabama Power	Power South	Georgia Power	OPC	MEAG Power	Dalton	Duke Energy Florida	Southern Power	OUC	FMPA	KUA
	(MWs)											
Plant Miller Units 1 and 2	1,320	91.8 %	8.2 %	— %	— %	— %	— %	— %	— %	— %	— %	— %
Plant Hatch	1,796	—	—	50.1	30.0	17.7	2.2	—	—	—	—	—
Plant Vogtle Units 1 and 2	2,320	—	—	45.7	30.0	22.7	1.6	—	—	—	—	—
Plant Scherer Units 1 and 2	1,636	—	—	8.4	60.0	30.2	1.4	—	—	—	—	—
Plant Wansley	1,779	—	—	53.5	30.0	15.1	1.4	—	—	—	—	—
Rocky Mountain	848	—	—	25.4	74.6	—	—	—	—	—	—	—
Intercession City, FL	143	—	—	33.3	—	—	—	66.7	—	—	—	—
Plant Stanton A	660	—	—	—	—	—	—	—	65 %	28 %	3.5 %	3.5 %

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

In addition, Georgia Power has commitments regarding a portion of a 5% interest in Plant Vogtle Units 1 and 2 owned by MEAG Power that are in effect until the later of retirement of the plant or the latest stated maturity date of MEAG Power's bonds issued to finance such ownership interest. The payments for capacity are required whether any capacity is available. The energy cost is a function of each unit's variable operating costs. Except for the portion of the capacity payments related to the Georgia PSC's disallowances of Plant Vogtle Units 1 and 2 costs, the cost of such capacity and energy is included in purchased power from non-affiliates in Georgia Power's statements of income in Item 8 herein. Also see Note 7 to the financial statements of Georgia Power under "Commitments — Purchased Power Commitments" in Item 8 herein for additional information.

Georgia Power is currently constructing Plant Vogtle Unts 3 and 4 which will be jointly owned by Georgia Power, Dalton, OPC, and MEAG Power. In addition, Mississippi Power is constructing the Kemper IGCC and expects to sell a 15% ownership interest in the Kemper IGCC to SMEPA. See Note 3 to the financial statements of Southern Company and Georgia Power under "Retail Regulatory Matters - Georgia Power - Nuclear Construction" and "Retail Regulatory Matters - Nuclear Construction," respectively. Also see Note 3 to the financial statements of each of Southern Company and Mississippi Power under "Integrated Coal Gasification Combined Cycle" for additional information.

Titles to Property

The traditional operating companies', Southern Power's, and SEGCO's interests in the principal plants (other than certain pollution control facilities and the land on which five combustion turbine generators of Mississippi Power are located, which is held by easement) and other important units of the respective companies are owned in fee by such companies, subject only to the liens pursuant to pollution control revenue bonds of Alabama Power and Gulf Power on specific pollution control facilities and liens pursuant to the assumption of debt obligations by Mississippi Power in connection with the acquisition of Plant Daniel Units 3 and 4. See Note 6 to the financial statements of Southern Company, Alabama Power, Gulf Power, and Mississippi Power under "Assets Subject to Lien" in Item 8 herein for additional information. The traditional operating companies own the fee interests in certain of their principal plants as tenants in common. See "Jointly-Owned Facilities" herein for additional information. Properties such as electric transmission and distribution lines, steam heating mains, and gas pipelines are constructed principally on rights-of-way which are maintained under franchise or are held by easement only. A substantial portion of lands submerged by reservoirs is held under flood right easements.

Subsequent to December 31, 2013, Georgia Power made borrowings through the Federal Financing Bank that were guaranteed by the DOE. Georgia Power's reimbursement obligations to the DOE under the loan guarantee are secured by a first priority lien on (i) Georgia Power's 45.7% undivided ownership interest in Plant Vogtle Units 3 and 4 and (ii) Georgia Power's rights and obligations under the principal contracts relating to Plant Vogtle Units 3 and 4. See Note 6 to the financial statements of each of Southern Company and Georgia Power under “DOE Loan Guarantee Borrowings” for additional information.

Item 3. LEGAL PROCEEDINGS

(1) United States of America v. Alabama Power (United States District Court for the Northern District of Alabama)
United States of America v. Georgia Power (United States District Court for the Northern District of Georgia)
See Note 3 to the financial statements of Southern Company and each traditional operating company under "Environmental Matters – New Source Review Actions" in Item 8 herein for information.
(2) Georgia Power et al. v. Westinghouse and Stone & Webster (United States District Court for the Southern District of Georgia Augusta Division)

Stone & Webster and Westinghouse v. Georgia Power et al. (United States District Court for the District of Columbia)
See Note 3 to the financial statements of Southern Company and Georgia Power under "Georgia Power – Nuclear Construction" and "Retail Regulatory Matters – Nuclear Construction," respectively, in Item 8 herein for information.
(3) Environmental Remediation
See Note 3 to the financial statements of Southern Company, Georgia Power, Gulf Power, and Mississippi Power under "Environmental Matters – Environmental Remediation" in Item 8 herein for information related to environmental remediation.
See Note 3 to the financial statements of each registrant in Item 8 herein for descriptions of additional legal and administrative proceedings discussed therein.

Item 4. MINE SAFETY DISCLOSURES

Not applicable.

EXECUTIVE OFFICERS OF SOUTHERN COMPANY
(Identification of executive officers of Southern Company is inserted in Part I in accordance with Regulation S-K, Item 401(b), Instruction 3.) The ages of the officers set forth below are as of December 31, 2013.
Thomas A. Fanning
Chairman, President, Chief Executive Officer, and Director
Age 56
Elected in 2003. Chairman and Chief Executive Officer since December 2010 and President since August 2010. Previously served as Executive Vice President and Chief Operating Officer from February 2008 through July 2010.
Art P. Beattie
Executive Vice President and Chief Financial Officer
Age 59
Elected in 2010. Executive Vice President and Chief Financial Officer since August 2010. Previously served as Executive Vice President, Chief Financial Officer, and Treasurer of Alabama Power from February 2005 through August 2010.
W. Paul Bowers
Executive Vice President
Age 57
Elected in 2001. Executive Vice President since February 2008 and Chief Executive Officer, President, and Director of Georgia Power since January 2011 and Chief Operating Officer of Georgia Power from August 2010 to December 2010. He previously served as Executive Vice President and Chief Financial Officer of Southern Company from February 2008 to August 2010.
S. W. Connally, Jr.
President and Chief Executive Officer of Gulf Power
Age 44
Elected in 2012. 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 and Manager of Alabama Power's Plant Barry from August 2007 through July 2010.
Mark A. Crosswhite (1)
Executive Vice President and Chief Operating Officer
Age 51
Elected in 2010. Executive Vice President and Chief Operating Officer since July 2012. Previously served as President, Chief Executive Officer, and Director of Gulf Power from January 2011 through June 2012 and Executive Vice President of External Affairs at Alabama Power from February 2008 through December 2010.
Kimberly S. Greene (2)
Executive Vice President
Age 47
Elected in 2013. President and Chief Executive Officer of SCS since April 2013. 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, Group President of Strategy and External Relations from 2010 through 2011, and Chief Financial Officer and Executive Vice President of Financial Services from 2007 through 2009.
G. Edison Holland, Jr.
Executive Vice President
Age 61
Elected in 2001. President, Chief Executive Officer, and Director of Mississippi Power since May 2013 and Executive Vice President of Southern Company since April 2001. Previously served as Corporate Secretary of Southern Company from April 2005 until May 2013 and General Counsel of Southern Company from April 2001 until May 2013.

Stephen E. Kuczynski
President and Chief Executive Officer of Southern Nuclear
Age 51
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 2006 to June 2011.

Charles D. McCrary (3)
Executive Vice President
Age 62
Elected in 1998. Executive Vice President since February 2002 and President, Chief Executive Officer, and Director of Alabama Power since October 2001.
Christopher C. Womack
Executive Vice President
Age 55
Elected in 2008. Executive Vice President and President of External Affairs since January 2009.
The officers of Southern Company were elected for a term running from the first meeting of the directors following the last annual meeting (May 22, 2013) for one year or until their successors are elected and have qualified.
(1) On February 10, 2014, Mr. Crosswhite was elected President and Chief Executive Officer of Alabama Power effective March 1, 2014. Mr. Crosswhite will resign from his role as Chief Operating Officer of Southern Company effective February 28, 2014. He will continue to serve as an Executive Vice President of Southern Company.
(2) On February 10, 2014, Ms. Greene was elected Chief Operating Officer of Southern Company effective March 1, 2014.
(3) On February 10, 2014, Mr. McCrary resigned the roles of President and Chief Executive Officer of Alabama Power effective March 1, 2014 and was elected by the Alabama Power Board of Directors as Chairman until his retirement on May 1, 2014.

EXECUTIVE OFFICERS OF ALABAMA POWER

(Identification of executive officers of Alabama Power is inserted in Part I in accordance with Regulation S-K, Item 401(b), Instruction 3.) The ages of the officers set forth below are as of December 31, 2013.

Charles D. McCrary (1)
President, Chief Executive Officer, and Director
Age 62
Elected in 2001. President, Chief Executive Officer, and Director since October 2001. Since February 2002, he has also served as Executive Vice President of Southern Company.

Philip C. Raymond
Executive Vice President, Chief Financial Officer, and Treasurer
Age 54
Elected in 2010. Executive Vice President, Chief Financial Officer, and Treasurer since August 2010. Previously served as Vice President and Chief Financial Officer of Gulf Power from May 2008 to August 2010.

Zeke W. Smith
Executive Vice President
Age 54
Elected in 2010. Executive Vice President of External Affairs since November 2010. Previously served as Vice President of Regulatory Services and Financial Planning from February 2005 to November 2010.

Steven R. Spencer
Executive Vice President
Age 58
Elected in 2001. Executive Vice President of the Customer Service Organization since February 2008.

James P. Heilbron
Senior Vice President and Senior Production Officer
Age 42
Elected in 2013. Senior Vice President and Senior Production Officer since March 2013. Previously served as Senior Vice President and Senior Production Officer of Southern Power Company from July 2010 to February 2013 and Plant Manager of Georgia Power's Plant Wansley from March 2006 to July 2010.

The officers of Alabama Power were elected for a term running from the meeting of the directors held on May 3, 2013 for one year or until their successors are elected and have qualified.

(1) On February 10, 2014, Mr. McCrary resigned the roles of President and Chief Executive Officer of Alabama Power effective March 1, 2014 and was elected by the Alabama Power Board of Directors as Chairman until his retirement on May 1, 2014. Mr. Mark A. Crosswhite was elected President and Chief Executive Officer of Alabama Power effective March 1, 2014.

EXECUTIVE OFFICERS OF GEORGIA POWER
(Identification of executive officers of Georgia Power is inserted in Part I in accordance with Regulation S-K, Item 401(b), Instruction 3.) The ages of the officers set forth below are as of December 31, 2013.
W. Paul Bowers
President, Chief Executive Officer, and Director
Age 57
Elected in 2010. Chief Executive Officer, President, and Director since December 2010 and Chief Operating Officer of Georgia Power from August 2010 to December 2010. He previously served as Executive Vice President and Chief Financial Officer of Southern Company from February 2008 to August 2010.
W. Craig Barrs
Executive Vice President
Age 56
Elected in 2008. Executive Vice President of External Affairs since January 2010. Previously served as Senior Vice President of External Affairs from January 2009 to January 2010.
W. Ron Hinson
Executive Vice President, Chief Financial Officer, and Treasurer
Age 57
Elected in 2013. Executive Vice President, Chief Financial Officer, and Treasurer since March 2013. Also, served as Comptroller from March 2013 until January 2014. Previously served as Comptroller and Chief Accounting Officer of Southern Company, as well as Senior Vice President and Comptroller of SCS from March 2006 to March 2013.
Joseph A. Miller
Executive Vice President
Age 52
Elected in 2009. Executive Vice President of Nuclear Development since May 2009. He also has served as Executive Vice President of Nuclear Development at Southern Nuclear since February 2006.
Anthony L. Wilson
Executive Vice President
Age 49
Elected in 2011. Executive Vice President of Customer Service and Operations since January 2012. Previously served as Vice President of Transmission from November 2009 to December 2011 and Vice President of Distribution from February 2007 to November 2009.
Thomas P. Bishop
Senior Vice President, Chief Compliance Officer, General Counsel, and Corporate Secretary
Age 53
Elected in 2008. Corporate Secretary since April 2011 and Senior Vice President, Chief Compliance Officer, and General Counsel since September 2008.
John L. Pemberton
Senior Vice President and Senior Production Officer
Age 43
Elected in 2012. Senior Vice President and Senior Production Officer since July 2012. Previously served as Senior Vice President and General Counsel for SCS and Southern Nuclear from June 2010 to July 2012 and Vice President of Governmental Affairs for SCS from August 2006 to June 2010.

The officers of Georgia Power were elected for a term running from the meeting of the directors held on May 15, 2013 for one year or until their successors are elected and have qualified.

EXECUTIVE OFFICERS OF MISSISSIPPI POWER
(Identification of executive officers of Mississippi Power is inserted in Part I in accordance with Regulation S-K, Item 401(b), Instruction 3.) The ages of the officers set forth below are as of December 31, 2013.
G. Edison Holland, Jr.
President, Chief Executive Officer, and Director
Age 61
Elected in 2013. President, Chief Executive Officer, and Director since May 2013 and Executive Vice President of Southern Company since April 2001. Previously served as Corporate Secretary of Southern Company from April 2005 until May 2013 and General Counsel of Southern Company from April 2001 until May 2013.
John W. Atherton
Vice President
Age 53
Elected in 2004. Vice President of Corporate Services and Community Relations since October 2012. Previously served as Vice President of External Affairs from January 2005 until October 2012.
John C. Huggins
Vice President
Age 62
Elected in 2013. Vice President of Generation Development since June 2013. Previously served as General Manager for the Kemper IGCC Startup, Engineering, and Construction Services from July 2010 to June 2013 and General Manager of Environmental Compliance Implementation from July 2005 to July 2010.
Moses H. Feagin
Vice President, Treasurer, and Chief Financial Officer
Age 49
Elected in 2010. Vice President, Treasurer, and Chief Financial Officer since August 2010. Previously served as Vice President and Comptroller of Alabama Power from May 2008 to August 2010.
Jeff G. Franklin
Vice President
Age 46
Elected in 2011. Vice President of Customer Services Organization since August 2011. Previously served as Georgia Power's Vice President of Governmental and Legislative Affairs from January 2011 to July 2011, Vice President of Governmental and Regulatory Affairs from March 2009 to January 2011, and Vice President of Sales from July 2008 to April 2009.
R. Allen Reaves
Vice President
Age 54
Elected in 2010. Vice President and Senior Production Officer since August 2010. Previously served as Manager of Mississippi Power's Plant Daniel from September 2007 through July 2010.
Billy F. Thornton
Vice President
Age 53
Elected in 2012. Vice President of Legislative and Regulatory Affairs since October 2012. Previously served as Director of External Affairs from October 2011 until October 2012, Director of Marketing from March 2011 through October 2011, and Major Account Sales Manager from June 2006 to March 2011.
The officers of Mississippi Power were elected for a term running from the meeting of the directors held on April 23, 2013 for one year or until their successors are elected and have qualified, except for Messrs. Holland and Huggins, whose elections were effective on May 20, 2013 and June 8, 2013, respectively.

PART II

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

(a)(1) The common stock of Southern Company is listed and traded on the New York Stock Exchange. The common stock is also traded on regional exchanges across the United States. The high and low stock prices as reported on the New York Stock Exchange for each quarter of the past two years were as follows:

	High	Low
2013		
First Quarter	$46.95	$42.82
Second Quarter	48.74	42.32
Third Quarter	45.75	40.63
Fourth Quarter	42.94	40.03
2012		
First Quarter	$46.06	$43.71
Second Quarter	48.45	44.22
Third Quarter	48.59	44.64
Fourth Quarter	47.09	41.75

There is no market for the other registrants' common stock, all of which is owned by Southern Company.
(a)(2) Number of Southern Company's common stockholders of record at January 31, 2014: 143,317
Each of the other registrants have one common stockholder, Southern Company.
(a)(3) Dividends on each registrant's common stock are payable at the discretion of their respective board of directors. The dividends on common stock declared by Southern Company and the traditional operating companies to their stockholder(s) for the past two years were as follows:

Registrant	Quarter	2013	2012
		(in thousands)	
Southern Company	First	$426,110	$410,040
	Second	443,684	426,891
	Third	443,963	429,711
	Fourth	448,073	426,450
Alabama Power	First	132,290	134,763
	Second	132,290	134,762
	Third	132,290	134,763
	Fourth	247,290	279,762
Georgia Power	First	226,750	227,075
	Second	226,750	227,075
	Third	226,750	227,075
	Fourth	226,750	302,075
Gulf Power	First	28,850	28,950
	Second	28,850	28,950
	Third	28,950	28,950
	Fourth	28,750	28,950
Mississippi Power	First	44,190	26,700
	Second	44,190	26,700
	Third	44,190	26,700

Fourth	44,190	26,700

II-1

In 2013 and 2012, Southern Power Company paid dividends to Southern Company as follows:

Registrant	Quarter	2013	2012
		(in thousands)	
Southern Power Company	First	$32,280	$31,750
	Second	32,280	31,750
	Third	32,280	31,750
	Fourth	32,280	31,750

The dividend paid per share of Southern Company's common stock was 49¢ for the first quarter 2013 and 50.75¢ each for the second, third, and fourth quarters of 2013. In 2012, Southern Company paid a dividend per share of 47.25¢ for the first quarter and 49¢ each for the second, third, and fourth quarters.

The traditional operating companies and Southern Power Company can only pay dividends to Southern Company out of retained earnings or paid-in-capital.

Southern Power Company's senior note indenture contains potential limitations on the payment of common stock dividends. At December 31, 2013, Southern Power Company was in compliance with the conditions of this senior note indenture and thus had no restrictions on its ability to pay common stock dividends. See Note 8 to the financial statements of Southern Company under "Common Stock Dividend Restrictions" and Note 6 to the financial statements of Southern Power under "Dividend Restrictions" in Item 8 herein for additional information regarding these restrictions.

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

See Part III, Item 12. Security Ownership of Certain Beneficial Owners and Management and Related Stockholder Matters under the heading "Equity Compensation Plan Information" herein.

(b) Use of Proceeds

Not applicable.

(c) Issuer Purchases of Equity Securities

None.

Item 6. SELECTED FINANCIAL DATA

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

Item 7A. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

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

Item 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA
INDEX TO 2013 FINANCIAL STATEMENTS

II-4

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

None.

Item 9A. CONTROLS AND PROCEDURES

Disclosure Controls And Procedures.

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

Mississippi Power reported in Item 9A of its Annual Report on Form 10-K/A for the year ended December 31, 2012 that management determined that Mississippi Power's failure to maintain sufficient evidence supporting certain estimated amounts included in the Kemper IGCC cost estimate and to fully communicate the related effects in the development of the Kemper IGCC cost estimate constituted a material weakness in internal control over financial reporting under the standards adopted by the Public Company Accounting Oversight Board. Mississippi Power's management completed the following actions in the second and third quarters of 2013 to remediate the material weakness in internal control over financial reporting:

- established a new governance team focused on accounting, legal, and regulatory affairs that meets regularly with the Kemper IGCC project and construction teams and provides further oversight around disclosures of the Kemper IGCC cost estimating process and schedule;
- re-emphasized and enhanced communication across functional areas and departments; and
- applied appropriate performance management actions.

In the fourth quarter 2013, Mississippi Power's management completed the actions to remediate the material weakness in internal control over financial reporting by refining and enhancing the Kemper IGCC project cost and schedule estimation methodologies and related documentation in addition to the items completed in the second and third quarters of 2013 noted above.

As of the end of the period covered by this annual report, Mississippi Power conducted an evaluation under the supervision and with the participation of management, including the Chief Executive Officer and the Chief Financial Officer, of the effectiveness of the design and operation of the disclosure controls and procedures (as defined in Sections 13a-15(e) and 15d-15(e) of the Securities Exchange Act of 1934). As part of this evaluation, Mississippi Power's management has determined that the remediation actions discussed above were effectively designed and demonstrated operating effectiveness for a sufficient period of time to enable Mississippi Power to conclude that the material weakness regarding its internal controls related to the Kemper IGCC cost estimate has been remediated as of December 31, 2013. Therefore, the Chief Executive Officer and the Chief Financial Officer concluded that the disclosure controls and procedures for this period were effective.

Internal Control Over Financial Reporting.

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

Southern Company's Management's Report on Internal Control Over Financial Reporting is included on page II-9 of this Form 10-K.

Alabama Power's Management's Report on Internal Control Over Financial Reporting is included on page II-118 of this
Form 10-K.

Georgia Power's Management's Report on Internal Control Over Financial Reporting is included on page II-196 of this Form 10-K.

Gulf Power's Management's Report on Internal Control Over Financial Reporting is included on page II-281 of this Form 10-K.
Mississippi Power's Management's Report on Internal Control Over Financial Reporting is included on page II-350 of this Form 10-K.
Southern Power's Management's Report on Internal Control Over Financial Reporting is included on page II-437 of this
Form 10-K.

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

The report of Deloitte & Touche LLP, Southern Company's independent registered public accounting firm, regarding Southern Company's internal control over financial reporting is included on page II-10 of this Form 10-K.

Not applicable to Alabama Power, Georgia Power, Gulf Power, Mississippi Power, and Southern Power Company because these companies are not accelerated filers or large accelerated filers.

(c) Changes in internal controls.

There have been no changes in Southern Company's, Alabama Power's, Georgia Power's, Gulf Power's, or Southern Power Company's internal control over financial reporting (as such term is defined in Rules 13a-15(f) and 15d-15(f) under the Securities Exchange Act of 1934) during the fourth quarter 2013 that have materially affected or are reasonably likely to materially affect Southern Company's, Alabama Power's, Georgia Power's, Gulf Power's, or Southern Power Company's internal control over financial reporting.

Other than the implementation of the actions described above under Item 9A, there have been no changes in Mississippi Power's internal control over financial reporting (as such term is defined in Rules 13a-15(f) and 15d-15(f) under the Securities Exchange Act of 1934) during the fourth quarter 2013 that have materially affected or are reasonably likely to materially affect Mississippi Power's internal control over financial reporting.

Item 9B. OTHER INFORMATION

None.

Table of Contents Index to Financial Statements

THE SOUTHERN COMPANY
AND SUBSIDIARY COMPANIES
FINANCIAL SECTION

Table of Contents Index to Financial Statements

MANAGEMENT'S REPORT ON INTERNAL CONTROL OVER FINANCIAL REPORTING

Southern Company and Subsidiary Companies 2013 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 (1992) 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, 2013.

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, 2013. Deloitte & Touche LLP's report on Southern Company's internal control over financial reporting is included herein.

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

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

February 27, 2014

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, 2013 and 2012, 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, 2013. We also have audited the Company's internal control over financial reporting as of December 31, 2013, based on criteria established in Internal Control - Integrated Framework (1992) issued by the Committee of Sponsoring Organizations of the Treadway Commission. The Company's management is responsible for these financial statements, for maintaining effective internal control over financial reporting, and for its assessment of the effectiveness of internal control over financial reporting, included in the accompanying Management's Report on Internal Control Over Financial Reporting (page II-9). Our responsibility is to express an opinion on these financial statements and an opinion on the Company's internal control over financial reporting based on our audits.

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

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

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

In our opinion, the consolidated financial statements (pages II-46 to II-113) referred to above present fairly, in all material respects, the financial position of Southern Company and Subsidiary Companies as of December 31, 2013 and 2012, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2013, 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, 2013, based on the criteria established in Internal Control - Integrated Framework (1992) issued by the Committee of Sponsoring Organizations of the Treadway Commission.

/s/ Deloitte & Touche LLP
Atlanta, Georgia
February 27, 2014

MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS
Southern Company and Subsidiary Companies 2013 Annual Report

OVERVIEW
Business Activities
The Southern Company (Southern Company or the Company) is a holding company that owns all of the common stock of the traditional operating companies – Alabama Power Company (Alabama Power), Georgia Power Company (Georgia Power), Gulf Power Company (Gulf Power), and Mississippi Power Company (Mississippi Power) – and Southern Power Company (Southern Power), and other direct and indirect subsidiaries (together, the Southern Company system). 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 given economic conditions, 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. Subsidiaries of Southern Company are constructing two new nuclear generating units at Plant Vogtle (Plant Vogtle Units 3 and 4) (45.7% ownership interest by Georgia Power in two units, each with approximately 1,100 megawatts (MWs)) and the 582-MW integrated coal gasification combined cycle facility under construction in Kemper County, Mississippi (Kemper IGCC) (in which Mississippi Power is ultimately expected to hold an 85% ownership interest). Each of the traditional operating companies has various regulatory mechanisms that operate to address cost recovery. Appropriately balancing required costs and capital expenditures with customer prices will continue to challenge the Southern Company system for the foreseeable future. In 2013, each of the traditional operating companies completed significant rate proceedings. 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 continues to execute its strategy through a combination of acquiring, constructing, and selling power plants, including renewable energy projects, and by entering into power purchase agreements (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.
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 fossil/hydro 2013 Peak Season EFOR was slightly better than the target; however, see FUTURE EARNINGS POTENTIAL – "Other Matters" herein for information regarding an explosion at Plant Bowen in April 2013 that negatively impacted the fossil/hydro 2013 Peak

Season EFOR. 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 performance for 2013 was better than the target for these reliability measures. Primarily as a result of charges for estimated probable losses related to construction of the Kemper IGCC, Southern Company's EPS for 2013 did not meet the target on a generally accepted accounting principles (GAAP) basis. See RESULTS OF OPERATIONS – "Estimated Loss on Kemper IGCC" and Note 3 to the financial statements under "Integrated Coal Gasification Combined Cycle" for additional information.

MANAGEMENT'S DISCUSSION AND ANALYSIS (continued)
Southern Company and Subsidiary Companies 2013 Annual Report

Excluding the charges for estimated probable losses related to construction of the Kemper IGCC and the restructuring of a leveraged lease, as well as proceeds from an insurance settlement, Southern Company's 2013 results compared with its targets for some of these key indicators are reflected in the following chart:

Key Performance Indicator	2013 Target Performance	2013 Actual Performance
System Customer Satisfaction	Top quartile in customer surveys	Top quartile
Peak Season System EFOR — fossil/hydro	5.86% or less	5.82%
Basic EPS — As Reported	\$2.68-\$2.80	\$1.88
Estimated Loss on Kemper IGCC(1)		\$0.83
Leveraged Lease Restructure(2)		\$0.02
MC Asset Recovery Insurance Settlement(3)		\$(0.02)
EPS, excluding items*		\$2.71

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

1. The estimated probable losses of \$729 million after-tax, or \$0.83 per share, relating to Mississippi Power's construction of the Kemper IGCC. See RESULTS OF OPERATIONS – "Estimated Loss on Kemper IGCC" and Note 3 to the financial statements under "Integrated Coal Gasification Combined Cycle" for additional information.
2. The \$16 million after-tax, or \$0.02 per share, charge related to the restructuring of a leveraged lease investment that was completed on March 1, 2013. See RESULTS OF OPERATIONS – "Other Business Activities – Other Income (Expense), Net" for additional information.
3. Insurance settlement proceeds of \$12 million after-tax, or \$0.02 per share, related to the March 2009 litigation settlement with MC Asset Recovery, LLC. See RESULTS OF OPERATIONS – "Other Business Activities – Other Operations and Maintenance Expenses" and Note 3 to the financial statements under "Insurance Recovery" for additional information.

Does not reflect EPS as calculated in accordance with GAAP. Southern Company management uses the non-GAAP measure of EPS, excluding items described above, to evaluate the performance of Southern Company's ongoing business activities. Southern Company believes the presentation of this non-GAAP measure of earnings is useful for investors because it provides earnings information that is consistent with the historical and ongoing business activities of the Company. The presentation of this information 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

Southern Company's net income after dividends on preferred and preference stock of subsidiaries was \$1.6 billion in 2013, a decrease of \$706 million, or 30.0%, from the prior year. The decrease was primarily the result of \$1.2 billion in pre-tax charges (\$729 million after-tax) for revisions of estimated costs expected to be incurred on Mississippi Power's construction of the Kemper IGCC above the \$2.88 billion cost cap established by the Mississippi Public Service Commission (PSC), net of \$245 million of grants awarded to the project by the U.S. Department of Energy (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 carbon dioxide (CO_2) pipeline facilities, allowance for funds used during construction (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 certificate of public convenience and necessity (CPCN)) (Cost Cap Exceptions). Also contributing to the decrease in net income were increases in depreciation and amortization and other operations and maintenance expenses, partially offset by increases in retail revenues and AFUDC.

Southern Company's net income after dividends on preferred and preference stock of subsidiaries was $2.4 billion in 2012, an increase of $147 million, or 6.7%, from the prior year. The increase was primarily the result of lower operations and maintenance expenses resulting from cost containment efforts in 2012, increases in revenues associated with the elimination of a tax-related adjustment under Alabama Power's rate structure, an increase related to retail revenue rate effects at Georgia Power, and an increase in revenues due to increases in retail base rates at Gulf Power. Also contributing to the increase were higher capacity revenues and an increase in retail sales growth. The increases were partially offset by milder weather and an increase in depreciation on additional plant in service related to new generation, transmission, distribution, and environmental projects.

Basic EPS was $1.88 in 2013, $2.70 in 2012, and $2.57 in 2011. Diluted EPS, which factors in additional shares related to stock-based compensation, was $1.87 in 2013, $2.67 in 2012, and $2.55 in 2011. EPS for 2013 was negatively impacted by $0.02 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 $2.0125 in 2013, $1.9425 in 2012, and $1.8725 in 2011. In January 2014, Southern Company declared a quarterly dividend of 50.75 cents per share. This is the 265th consecutive quarter that Southern Company has paid a dividend equal to or higher than the previous quarter. For 2013, the actual payout ratio was 107%, while the payout ratio of net income excluding charges for estimated probable losses relating to Mississippi Power's construction of the Kemper IGCC and the restructuring of a leveraged lease investment as well as proceeds from the MC Asset Recovery insurance settlement was 74%.

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 2013 (in millions)	2012	2011
Electricity business	$1,652	$2,321	$2,214
Other business activities	(8)	29	(11)
Net income	$1,644	$2,350	$2,203

Electricity Business

Southern Company's electric utilities generate and sell electricity to retail and wholesale customers in the Southeast. A condensed statement of income for the electricity business follows:

	Amount	Increase (Decrease) from Prior Year	
	2013 (in millions)	2013	2012
Electric operating revenues	$17,035	$557	$(1,109)
Fuel	5,510	453	(1,205)
Purchased power	461	(83)	(64)
Other operations and maintenance	3,778	83	(147)
Depreciation and amortization	1,886	114	72
Taxes other than income taxes	932	20	13
Estimated loss on Kemper IGCC	1,180	1,180	—
Total electric operating expenses	13,747	1,767	(1,331)
Operating income	3,288	(1,210)	222
Allowance for equity funds used during construction	190	47	(10)
Interest income	18	(4)	3
Interest expense, net of amounts capitalized	788	(32)	17
Other income (expense), net	(55)	2	16
Income taxes	935	(465)	107
Net income	1,718	(668)	107
Dividends on preferred and preference stock of subsidiaries	66	1	—
Net income after dividends on preferred and preference stock of subsidiaries	$1,652	$(669)	$107

MANAGEMENT'S DISCUSSION AND ANALYSIS (continued)
Southern Company and Subsidiary Companies 2013 Annual Report

Electric Operating Revenues
Electric operating revenues for 2013 were $17.0 billion, reflecting a $557 million increase from 2012. Details of electric operating revenues were as follows:

	Amount	
	2013	2012
	(in millions)	
Retail — prior year	$14,187	$15,071
Estimated change resulting from —		
Rates and pricing	137	296
Sales growth (decline)	(2)	39
Weather	(40)	(282)
Fuel and other cost recovery	259	(937)
Retail — current year	14,541	14,187
Wholesale revenues	1,855	1,675
Other electric operating revenues	639	616
Electric operating revenues	$17,035	$16,478
Percent change	3.4%	(6.3)%

Retail revenues increased $354 million, or 2.5%, in 2013 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 2013 was primarily due to base tariff increases at Georgia Power effective April 1, 2012 and January 1, 2013, as approved by the Georgia PSC, related to placing new generating units at Plant McDonough-Atkinson in service and collecting financing costs related to the construction of Plant Vogtle Units 3 and 4 through the Nuclear Construction Cost Recovery (NCCR) tariff, as well as higher contributions from market-driven rates from commercial and industrial customers.

Retail revenues decreased $884 million, or 5.9%, in 2012 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 2012 was primarily due to increases in retail revenues at Georgia Power due to base tariff increases effective April 1, 2012 related to placing Plant McDonough-Atkinson Units 4 and 5 in service, collecting financing costs related to the construction of Plant Vogtle Units 3 and 4 through the NCCR tariff, and demand-side management programs effective January 1, 2012, as approved by the Georgia PSC, as well as the rate pricing effect of decreased customer usage. Also contributing to the increase were the elimination of a tax-related adjustment under Alabama Power's rate structure that was effective with October 2011 billings and higher revenues due to increases in retail base rates at Gulf Power. These increases were partially offset by lower contributions from market-driven rates from commercial and industrial customers at Georgia Power and decreased revenues under rate certificated new plant environmental (Rate CNP Environmental) at Alabama Power.

See FUTURE EARNINGS POTENTIAL – "PSC Matters – Alabama Power – Retail Rate Adjustments" and "PSC Matters – Georgia Power – Rate Plans" herein 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, storm damage, new plants, and PPAs.

Wholesale revenues consist of PPAs with investor-owned utilities and electric cooperatives and short-term opportunity sales. Wholesale revenues from 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. 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.

MANAGEMENT'S DISCUSSION AND ANALYSIS (continued)
Southern Company and Subsidiary Companies 2013 Annual Report

Wholesale revenues from power sales were as follows:

	2013	2012	2011
	(in millions)		
Capacity and other	$955	$882	$820
Energy	900	793	1,085
Total	$1,855	$1,675	$1,905

In 2013, wholesale revenues increased $180 million, or 10.7%, as compared to the prior year due to a $107 million increase in energy revenues and a $73 million increase in capacity revenues. The increase in energy revenues was primarily related to an increase in the average price of energy and new solar contracts served by Southern Power's Plants Campo Verde and Spectrum, which began in 2013, partially offset by a decrease in volume related to milder weather as compared to the prior year. The increase in capacity revenues was primarily due to a new PPA served by Southern Power's Plant Nacogdoches, which began in June 2012, and an increase in capacity amounts under existing PPAs.

In 2012, wholesale revenues decreased $230 million, or 12.1%, as compared to the prior year due to a $292 million decrease in energy sales primarily due to a reduction in the average price of energy and lower customer demand, partially offset by a $62 million increase in capacity revenues.

Other Electric Revenues

Other electric revenues increased $23 million, or 3.7%, and $5 million, or 0.8%, in 2013 and 2012, respectively, as compared to the prior years. The 2013 increase in other electric revenues was primarily a result of increases in transmission revenues related to the open access transmission tariff and rents from electric property related to pole attachments. Other electric revenues increased in 2012 primarily due to an increase in rents from electric property.

Energy Sales

Changes in revenues are influenced heavily by the change in the volume of energy sold from year to year. Kilowatt-hour (KWH) sales for 2013 and the percent change by year were as follows:

	Total KWHs	Total KWH Percent Change		Weather-Adjusted Percent Change	
	2013	2013	2012	2013*	2012
	(in billions)				
Residential	50.6	0.2 %	(5.4)%	(0.3)%	1.1 %
Commercial	52.6	(0.9)	(1.6)	(0.1)	(0.2)
Industrial	52.4	1.5	0.2	1.5	0.2
Other	0.9	(1.8)	(1.8)	(1.9)	(1.4)
Total retail	156.5	0.3	(2.3)	0.4 %	0.4 %
Wholesale	26.9	(2.2)	(9.2)		
Total energy sales	183.4	(0.1)%	(3.4)%		

* In the first quarter 2012, Georgia Power began using new actual advanced meter data to compute unbilled revenues. The weather-adjusted KWH sales variances shown above reflect an adjustment to the estimated allocation of Georgia Power's unbilled January 2012 KWH sales among customer classes that is consistent with the actual allocation in 2013. Without this adjustment, 2013 weather-adjusted residential KWH sales decreased 0.5% as compared to 2012 while weather-adjusted commercial KWH sales increased 0.2% as compared to 2012.

Changes in retail energy sales are comprised of changes in electricity usage by customers, changes in weather, and changes in the number of customers. Retail energy sales increased 403 million KWHs in 2013 as compared to the prior year. This increase was primarily the result of customer growth, partially offset by milder weather and a decrease in customer usage. Weather-adjusted residential and commercial energy sales remained relatively flat compared to the prior year with a decrease in customer usage, offset by customer growth. The increase in industrial energy sales was primarily due to increased demand in the paper, primary metals, and stone, clay, and glass sectors.

Retail energy sales decreased 3.6 billion KWHs in 2012 as compared to the prior year. This decrease was primarily the result of milder weather in 2012, partially offset by customer growth and an increase in customer usage primarily in the residential class.

Wholesale energy sales decreased 619 million KWHs in 2013 and 2.8 billion KWHs in 2012 as compared to the prior years. The decreases in wholesale energy sales were primarily related to lower customer demand resulting from milder weather as compared to the prior years.

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:

	2013	2012	2011
Total generation (billions of KWHs)	179	175	186
Total purchased power (billions of KWHs)	12	16	12
Sources of generation (percent) —			
Coal	39	38	52
Nuclear	17	18	16
Gas	40	42	30
Hydro	4	2	2
Cost of fuel, generated (cents per net KWH) —			
Coal	4.01	3.96	4.02
Nuclear	0.87	0.83	0.72
Gas	3.29	2.86	3.89
Average cost of fuel, generated (cents per net KWH)	3.17	2.93	3.43
Average cost of purchased power (cents per net KWH) *	5.27	4.45	6.32

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

In 2013, total fuel and purchased power expenses were $6.0 billion, an increase of $370 million, or 6.6%, as compared to the prior year. This increase was primarily the result of a $446 million increase in the average cost of fuel and purchased power primarily due to higher natural gas prices and a $113 million increase in the volume of KWHs generated, partially offset by a $189 million decrease in the volume of KWHs purchased as the marginal cost of generation available was lower than the market cost of available energy.

In 2012, total fuel and purchased power expenses were $5.6 billion, a decrease of $1.3 billion, or 18.5%, as compared to the prior year. This decrease was primarily the result of a $1.0 billion decrease in the average cost of fuel and purchased power and a $519 million decrease in the volume of KWHs generated as a result of milder weather in 2012, partially offset by a $270 million increase in the volume of KWHs purchased.

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 – "PSC 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 2013, fuel expense was $5.5 billion, an increase of $453 million, or 9.0%, as compared to the prior year. The increase was primarily due to a 15.0% increase in the average cost of natural gas per KWH generated, partially offset by a 125.9% increase in the volume of KWHs generated by hydro facilities resulting from greater rainfall.

In 2012, fuel expense was $5.1 billion, a decrease of $1.2 billion, or 19.2%, as compared to the prior year. The decrease was primarily due to a 26.5% decrease in the average cost of natural gas per KWH generated, a higher percentage of generation from lower-cost natural gas-fired resources, and lower customer demand mainly due to milder weather in 2012.

Purchased Power

In 2013, purchased power expense was $461 million, a decrease of $83 million, or 15.3%, as compared to the prior year. The decrease was due to a 25.9% decrease in the volume of KWHs purchased as the marginal cost of generation available was lower than the market cost of available energy, partially offset by an 18.4% increase in the average cost per KWH purchased.

In 2012, purchased power expense was $544 million, a decrease of $64 million, or 10.5%, as compared to the prior year. The decrease was due to a 29.6% decrease in the average cost per KWH purchased, partially offset by a 35.1% increase in the volume of KWHs purchased as the market cost of available energy was lower than the marginal cost of generation available.

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 $83 million, or 2.2%, in 2013 and decreased $147 million, or 3.8%, in 2012 as compared to the prior years. Other operations and maintenance expenses in 2013 and 2012 were significantly below normal levels as a result of cost containment efforts undertaken primarily at Georgia Power to offset the impact of significantly milder than normal weather conditions. Discussion of significant variances for components of other operations and maintenance expenses follows.

Other production expenses at fossil, hydro, and nuclear plants decreased $7 million and $110 million in 2013 and 2012, respectively, as compared to the prior years. Production expenses fluctuate from year to year due to variations in outage schedules and changes in the cost of labor and materials. The decrease in other production expenses in 2013 was not material. Other production expenses decreased in 2012 primarily due to a decrease in scheduled outage and maintenance costs and commodity and labor costs, which was primarily the result of cost containment efforts to offset the effect of milder weather in 2012. Also contributing to the decrease was a $35 million decrease at Mississippi Power related to the expiration of the operating lease for Plant Daniel Units 3 and 4, which was offset by a $35 million increase at Alabama Power primarily related to a change in the nuclear maintenance outage accounting process associated with routine refueling activities, as approved by the Alabama PSC in 2010. See FUTURE EARNINGS POTENTIAL – "PSC Matters – Alabama Power – Nuclear Outage Accounting Order" herein for additional information.

Transmission and distribution expenses increased $27 million in 2013 and decreased $75 million in 2012 as compared to the prior years. Transmission and distribution expenses fluctuate from year to year due to variations in maintenance schedules and normal changes in the cost of labor and materials. Transmission and distribution expenses increased in 2013 primarily due to increases at Georgia Power in transmission system load expense resulting from billing adjustments with integrated transmission system owners. Transmission and distribution expenses decreased in 2012 primarily due to cost containment efforts to offset the effects of the milder weather in 2012 and a reduction in accruals at Alabama Power to the natural disaster reserve (NDR). See FUTURE EARNINGS POTENTIAL – "PSC Matters – Alabama Power – Natural Disaster Reserve" herein for additional information.

Customer accounts, sales, and service expenses remained relatively flat in 2013 and decreased $20 million in 2012 as compared to the prior years primarily due to a decrease in uncollectible account expense at Georgia Power.

Administrative and general expenses increased $63 million and $58 million in 2013 and 2012, respectively, as compared to the prior years primarily as a result of an increase in pension costs.

Depreciation and Amortization

Depreciation and amortization increased $114 million, or 6.4%, in 2013 as compared to the prior year primarily due to additional plant in service related to the completion of Georgia Power's Plant McDonough-Atkinson Units 5 and 6 in April 2012 and October 2012, respectively, and six Southern Power plants between June 2012 and October 2013, certain coal unit retirement decisions (with respect to the portion of such units dedicated to wholesale service) at

Georgia Power, and additional transmission and distribution projects. See FUTURE EARNINGS POTENTIAL – "PSC Matters – Georgia Power – Integrated Resource Plan" for additional information on Georgia Power's unit retirement decisions. These increases were partially offset by a net reduction in amortization primarily related to amortization of a regulatory liability for state income tax credits at Georgia Power and by the deferral of certain expenses under an accounting order at Alabama Power. See Note 1 to the financial statements under "Regulatory Assets and Liabilities" for additional information on the state income tax credits regulatory liability. Also see FUTURE EARNINGS POTENTIAL – "PSC Matters – Alabama Power – Compliance and Pension Cost Accounting Order" herein and Note 3 to the financial statements under "Retail Regulatory Matters – Alabama Power – Compliance and Pension Cost Accounting Order" for additional information on Alabama Power's accounting order.

MANAGEMENT'S DISCUSSION AND ANALYSIS (continued)
Southern Company and Subsidiary Companies 2013 Annual Report

Depreciation and amortization increased $72 million, or 4.2%, in 2012 as compared to the prior year primarily as a result of additional plant in service related to new generation at Georgia Power's Plant McDonough-Atkinson Units 4 and 5, additional plant in service at Southern Power, as well as transmission, distribution, and environmental projects, partially offset by amortization of a regulatory liability for state income tax credits at Georgia Power as authorized by the Georgia PSC.
See Note 1 to the financial statements under "Regulatory Assets and Liabilities" and "Depreciation and Amortization" for additional information.
Taxes Other Than Income Taxes
Taxes other than income taxes increased $20 million, or 2.2%, in 2013 as compared to the prior year primarily due to increases in property taxes. Taxes other than income taxes increased $13 million, or 1.4%, in 2012 as compared to the prior year primarily due to increases in property taxes, partially offset by a decrease in municipal franchise fees, which are based on revenues from energy sales.
Estimated Loss on Kemper IGCC
In 2013, estimated probable losses on the Kemper IGCC of $1.2 billion were recorded at Southern Company to 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 the DOE Grants and excluding the Cost Cap Exceptions. See FUTURE EARNINGS POTENTIAL – "Construction Program" herein and Note 3 to the financial statements under "Integrated Coal Gasification Combined Cycle" for additional information.
Allowance for Equity Funds Used During Construction
AFUDC equity increased $47 million, or 32.9%, in 2013 as compared to the prior year primarily due to an increase in construction work in progress (CWIP) related to the construction of Mississippi Power's Kemper IGCC and increased capital expenditures at Alabama Power, partially offset by the completion of Georgia Power's Plant McDonough-Atkinson Units 5 and 6 in 2012. See Note 3 to the financial statements under "Integrated Coal Gasification Combined Cycle" for additional information regarding the Kemper IGCC.
AFUDC equity decreased $10 million, or 6.5%, in 2012 as compared to the prior year primarily due to the completion of Georgia Power's Plant McDonough-Atkinson Units 4, 5, and 6 in December 2011, April 2012, and October 2012, respectively, partially offset by increases in CWIP related to the construction of Mississippi Power's Kemper IGCC.
Interest Expense, Net of Amounts Capitalized
Total interest charges and other financing costs decreased $32 million, or 3.9%, in 2013 as compared to the prior year primarily due to lower interest rates, the timing of issuances and redemptions of long-term debt, an increase in capitalized interest primarily resulting from AFUDC debt associated with Mississippi Power's Kemper IGCC, and an increase in capitalized interest associated with the construction of Southern Power's Plants Campo Verde and Spectrum. These decreases were partially offset by a decrease in capitalized interest resulting from the completion of Southern Power's Plants Nacogdoches and Cleveland, a reduction in AFUDC debt due to the completion of Georgia Power's Plant McDonough-Atkinson Units 5 and 6, and the conclusion of certain state and federal tax audits in 2012.
Total interest charges and other financing costs increased $17 million, or 2.1%, in 2012 as compared to the prior year primarily due to a $23 million reduction in interest expense in 2011 at Georgia Power resulting from the settlement of litigation with the Georgia Department of Revenue, a decrease in AFUDC debt at Georgia Power due to the completion of Plant McDonough-Atkinson Units 4 and 5, and a net increase in interest expense related to senior notes and other long-term debt. The increases were partially offset by a decrease in interest expense on existing variable rate pollution control revenue bonds, an increase in capitalized interest primarily resulting from AFUDC debt associated with the Kemper IGCC at Mississippi Power, and a decrease related to the conclusion of certain state and federal income tax audits.
Other Income (Expense), Net

In 2013, the change in other income (expense), net was not material. Other income (expense), net increased $16 million, or 21.9%, in 2012 as compared to the prior year primarily due to a make-whole premium payment in connection with the early redemption of senior notes at Southern Power in 2011.

MANAGEMENT'S DISCUSSION AND ANALYSIS (continued)
Southern Company and Subsidiary Companies 2013 Annual Report

Income Taxes
Income taxes decreased $465 million, or 33.2%, in 2013 as compared to the prior year primarily due to lower pre-tax earnings, an increase in tax benefits recognized from investment tax credits at Southern Power, and a net increase in non-taxable AFUDC equity, partially offset by a decrease in state income tax credits, primarily at Georgia Power.
Income taxes increased $107 million, or 8.3%, in 2012 as compared to the prior year primarily due to higher pre-tax earnings, an increase in non-deductible book depreciation, and a decrease in non-taxable AFUDC equity, partially offset by state income tax credits.
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 Southern Communications Services, Inc. (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.
A condensed statement of income for Southern Company's other business activities follows:

	Amount	Increase (Decrease) from Prior Year	
	2013	2013	2012
	(in millions)		
Operating revenues	$52	$(7)	$(11)
Other operations and maintenance	68	(9)	(19)
Depreciation and amortization	15	—	(2)
Taxes other than income taxes	2	—	—
Total operating expenses	85	(9)	(21)
Operating income (loss)	(33)	2	10
Interest income	1	(17)	16
Equity in income (losses) of unconsolidated subsidiaries	—	2	—
Other income (expense), net	(26)	(47)	7
Interest expense	36	(3)	(15)
Income taxes	(86)	(20)	8
Net income (loss)	$(8)	$(37)	$40

Operating Revenues
Southern Company's non-electric operating revenues from these other business activities decreased $7 million, or 11.9%, and $11 million, or 15.7%, in 2013 and 2012, respectively, as compared to the prior years. The decreases were primarily the result of 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 businesses decreased $9 million, or 11.7%, and $19 million, or 19.8%, in 2013 and 2012, respectively, as compared to the prior years. The decrease in 2013 was primarily related to lower operating expenses at SouthernLINC Wireless and decreases in consulting and legal fees, partially offset by higher operating expenses at Southern Holdings and a decrease in the amount of insurance proceeds received in 2013 related to the litigation settlement with MC Asset Recovery, LLC as compared to the amount received in 2012. The decrease in 2012 was primarily related to the insurance proceeds received in 2012. See Note 3 to the financial statements under "Insurance Recovery" for additional information.

Interest Income

Interest income for these other businesses decreased $17 million in 2013 and increased $16 million in 2012 as compared to the prior years primarily due to the conclusion of certain federal income tax audits in 2012.

Other Income (Expense), Net

Other income (expense), net for these other businesses decreased $47 million in 2013 and increased $7 million in 2012 as compared to the prior years. The decrease in 2013 was primarily due to the restructuring of a leveraged lease investment and an increase in charitable contributions. The increase in 2012 was primarily due to a decrease in charitable contributions.

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 under "Leveraged Leases" for additional information.

Interest Expense

Total interest charges and other financing costs for these other businesses decreased $3 million, or 7.7%, and $15 million, or 27.8%, in 2013 and 2012, respectively, as compared to the prior years. The decrease in 2013 was not material. The decrease in 2012 was primarily related to lower interest rates on existing debt.

Income Taxes

Income taxes for these other businesses decreased $20 million, or 30.3%, in 2013 as compared to the prior year primarily as a result of higher pre-tax losses. Income taxes for these other businesses increased $8 million, or 10.8%, in 2012 as compared to the prior year primarily as a result of lower pre-tax 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 Federal Energy Regulatory Commission (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, optimized by limited energy trading activities. 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 continues to allow for the timely recovery of prudently-incurred costs during a time of increasing costs and the successful completion of Plant Vogtle Units 3 and 4 and the Kemper IGCC as well as other ongoing construction projects. Another major factor is the profitability of the competitive wholesale supply business. Future earnings for the electricity business in the near term will depend, in part, upon maintaining energy sales which is 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 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 supply business also depends on numerous factors including creditworthiness of customers, total generating capacity available and related costs, future acquisitions and construction of generating facilities, and the successful remarketing of capacity as current contracts expire. Changes in regional and global economic conditions impact sales for the traditional operating companies and Southern Power, as the pace of the economic recovery remains uncertain. The timing and extent of the economic recovery will impact growth and 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.

Environmental Matters

Compliance costs related to federal and state environmental statutes and regulations could affect earnings if such costs cannot continue to be fully recovered in rates on a timely basis. Environmental compliance spending over the next several years may differ materially from the amounts estimated. The timing, specific requirements, and estimated costs could change as environmental statutes and regulations are adopted or modified. 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.

New Source Review Actions

As part of a nationwide enforcement initiative against the electric utility industry which began in 1999, the U.S. Environmental Protection Agency (EPA) brought civil enforcement actions in federal district court against Alabama Power and Georgia Power alleging violations of the New Source Review (NSR) provisions of the Clean Air Act at certain coal-fired electric generating units, including units co-owned by Gulf Power and Mississippi Power. These civil actions seek penalties and injunctive relief, including orders requiring installation of the best available control technologies at the affected units. The case against Georgia Power (including claims related to a unit co-owned by Gulf Power) has been administratively closed in the U.S. District Court for the Northern District of Georgia since 2001. The case against Alabama Power (including claims involving a unit co-owned by Mississippi Power) has been actively litigated in the U.S. District Court for the Northern District of Alabama, resulting in a settlement in 2006 of the alleged NSR violations at Plant Miller; voluntary dismissal of certain claims by the EPA; and a grant of summary judgment for Alabama Power on all remaining claims and dismissal of the case with prejudice in 2011. On September 19, 2013, the U.S. Court of Appeals for the Eleventh Circuit affirmed in part and reversed in part the 2011 judgment in favor of Alabama Power, and the case has been transferred back to the U.S. District Court for the Northern District of Alabama for further proceedings.

Southern Company believes the traditional operating companies complied with applicable laws and regulations in effect at the time the work in question took place. The Clean Air Act authorizes maximum civil penalties of $25,000 to $37,500 per day, per violation, depending on the date of the alleged violation. An adverse outcome could require substantial capital expenditures that cannot be determined at this time and could possibly require payment of substantial penalties. Such expenditures could affect future results of operations, cash flows, and financial condition if such costs are not recovered through regulated rates. The ultimate outcome of these matters cannot be determined at this time.

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; 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 2013, the traditional operating companies had invested approximately $9.4 billion in environmental capital retrofit projects to comply with these requirements, with annual totals of approximately $712 million, $340 million, and $300 million for 2013, 2012, and 2011, respectively. The Southern Company system expects that capital expenditures to comply with environmental statutes and regulations will total approximately $3.2 billion from 2014 through 2016, with annual

totals of approximately $1.5 billion, $1.1 billion, and $600 million for 2014, 2015, and 2016, respectively.
The Southern Company system continues to monitor the development of the EPA's proposed water and coal combustion residuals rules and to evaluate compliance options. Based on its preliminary analysis and an assumption that coal combustion residuals will continue to be regulated as non-hazardous solid waste under the proposed rule, the Southern Company system does not anticipate that material compliance costs with respect to these proposed rules will be required during the period of 2014 through 2016. The ultimate capital expenditures and compliance costs with respect to these proposed rules, including additional expenditures required after 2016, will be dependent on the requirements of the final rules and regulations adopted by the EPA and the outcome of any legal challenges to these rules. See "Water Quality" and "Coal Combustion Residuals" 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 and regulations relating to global climate change that are promulgated, including the proposed 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, and adding or changing fuel sources for certain existing units. The ultimate outcome of these matters cannot be determined at this time. See "PSC Matters – Georgia Power – Integrated Resource Plans" herein for additional information on planned unit retirements and fuel conversions at Georgia Power.

Southern Electric Generating Company (SEGCO) is jointly owned by Alabama Power and Georgia Power. As part of its environmental compliance strategy, SEGCO plans to add natural gas as the primary fuel source for its generating units in 2015. The capacity of SEGCO's units is sold equally to Alabama Power and Georgia Power through a PPA. If such compliance costs cannot continue to be recovered through retail rates, they could have a material financial impact on Southern Company's financial statements. See Note 4 to the financial statements for additional information.

Compliance with any new federal or state legislation or regulations relating to air quality, water, coal combustion residuals, global climate change, 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. Since 1990, the electric utilities have spent approximately $8.0 billion in reducing and monitoring emissions pursuant to the Clean Air Act. Additional controls are currently planned or under consideration to further reduce air emissions, maintain compliance with existing regulations, and meet new requirements.

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 more stringent eight-hour ozone NAAQS, which it began to implement in 2011. In May 2012, the EPA published its final determination of nonattainment areas based on the 2008 eight-hour ozone NAAQS. The only area within the traditional operating companies' service territory designated as a nonattainment area is a 15-county area within metropolitan Atlanta.

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 some former nonattainment areas within the service territory as attainment for these standards. Redesignation requests for certain areas designated as nonattainment in Georgia are still pending with the EPA. On January 15, 2013, the EPA published a final rule that increases the stringency of the annual fine particulate matter standard. The new standard could result in the designation of new nonattainment areas within the traditional operating companies' service territories.

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 may designate additional areas as nonattainment in the future, which could include 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.

On February 13, 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. On March 6, 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 by Mississippi Power, and units owned by SEGCO.

Each of the states in which the Southern Company system has fossil generation is subject to the requirements of the Clean Air Interstate Rule (CAIR), which calls for phased reductions in SO_2 and nitrogen oxide (NO_x) emissions from power plants in 28 eastern states. In 2008, the U.S. Court of Appeals for the District of Columbia Circuit issued decisions invalidating CAIR, but left CAIR compliance requirements in place while the EPA developed a new rule. In 2011, the EPA promulgated the Cross State Air

Pollution Rule (CSAPR) to replace CAIR. However, in August 2012, the U.S. Court of Appeals for the District of Columbia Circuit vacated CSAPR in its entirety and directed the EPA to continue to administer CAIR pending the EPA's development of a valid replacement. Review of the U.S. Court of Appeals for the District of Columbia Circuit's decision regarding CSAPR is currently pending before the U.S. Supreme Court.

The EPA finalized the Clean Air Visibility Rule (CAVR) 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 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 February 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. Compliance for existing sources is required by April 16, 2015; however, states may authorize a compliance extension of up to one year to April 16, 2016. Compliance extensions have been granted for some of the affected units owned or operated by the traditional operating companies.

In August 2012, the EPA published proposed revisions to the New Source Performance Standard (NSPS) for Stationary Combustion Turbines (CTs). 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 February 12, 2013, the EPA proposed a rule that would require certain states to revise the provisions of their SIPs relating to the regulation of excess emissions at industrial facilities, including fossil fuel-fired generating facilities, during periods of startup, shut-down, or malfunction (SSM). The EPA proposes a determination that the SSM provisions in the SIPs for 36 states (including Alabama, Florida, Georgia, Mississippi, and North Carolina) do not meet the requirements of the Clean Air Act and must be revised within 18 months of the date on which the EPA publishes the final rule. The EPA has entered into a settlement agreement requiring it to finalize the rule by June 12, 2014.

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. The impacts of the eight-hour ozone, fine particulate matter and SO_2 NAAQS, the Alabama opacity rule, CAIR and any future replacement rule, CAVR, 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 recently finalized and future rules, the resolution of pending and future legal challenges, and the development and implementation of rules at the state level. These regulations could result in significant additional 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. Further, higher costs that are recovered through regulated rates could contribute to reduced demand for electricity, which could negatively impact results of operations, cash flows, and financial condition.

In addition to the federal air quality laws described above, Georgia Power is also subject to the requirements of the 2007 State of Georgia Multi-Pollutant Rule. The Multi-Pollutant Rule, as amended, is designed to reduce emissions of mercury, SO_2, and NO_x state-wide by requiring the installation of specified control technologies at certain coal-fired generating units by specific dates between December 31, 2008 and April 16, 2015. A companion rule requires a 95% reduction in SO_2 emissions from the controlled units on the same or similar timetable. Through December 31, 2013, Georgia Power had installed the required controls on 13 of its largest coal-fired generating units with projects on three additional units to be completed before the unit-specific installation deadlines.

Water Quality

In 2011, the EPA published a proposed rule that establishes standards for reducing effects on fish and other aquatic life caused by cooling water intake structures at existing power plants and manufacturing facilities. The rule also addresses cooling water intake structures for new units at existing facilities. Compliance with the proposed rule could require changes to existing cooling water intake structures at certain of the traditional operating companies' and Southern Power's generating facilities, and new generating units constructed at existing plants would be required to install closed cycle cooling towers. The EPA is required to issue a final rule by April 17, 2014.

On June 7, 2013, the EPA published a proposed rule which requested comments on a range of potential regulatory options for addressing certain wastestreams from steam electric power plants. These regulations could result in the installation of additional controls at certain of the facilities of the traditional operating companies and Southern Power, which could result in significant capital expenditures and compliance costs that could affect future unit retirement and replacement decisions, depending on the specific technology requirements of the final rule.

The impact of these proposed rules cannot be determined at this time and will depend on the specific provisions of the final rules and the outcome of any legal challenges. These 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. Further, higher costs that are recovered through regulated rates could contribute to reduced demand for electricity, which could negatively impact results of operations, cash flows, and financial condition.

Coal Combustion Residuals

The traditional operating companies currently operate 22 electric generating plants with on-site coal combustion residuals storage facilities. In addition to on-site storage, the traditional operating companies also sell a portion of their coal combustion residuals to third parties for beneficial reuse. Historically, individual states have regulated coal combustion residuals and the states in the Southern Company system's service territory each have their own regulatory requirements. Each traditional operating company has a routine and robust inspection program in place to ensure the integrity of its coal ash surface impoundments and compliance with applicable regulations.

The EPA continues to evaluate the regulatory program for coal combustion residuals, including coal ash and gypsum, under federal solid and hazardous waste laws. In 2010, the EPA published a proposed rule that requested comments on two potential regulatory options for the management and disposal of coal combustion residuals: regulation as a solid waste or regulation as if the materials technically constituted a hazardous waste. Adoption of either option could require closure of, or significant change to, existing storage facilities and construction of lined landfills, as well as additional waste management and groundwater monitoring requirements. Under both options, the EPA proposes to exempt the beneficial reuse of coal combustion residuals from regulation; however, a hazardous or other designation indicative of heightened risk could limit or eliminate beneficial reuse options. Environmental groups and other parties have filed lawsuits in the U.S. District Court for the District of Columbia seeking to require the EPA to complete its rulemaking process and issue final regulations pertaining to the regulation of coal combustion residuals. On September 30, 2013, the U.S. District Court for the District of Columbia issued an order granting partial summary judgment to the environmental groups and other parties, ruling that the EPA has a statutory obligation to review and revise, as necessary, the federal solid waste regulations applicable to coal combustion residuals. On January 29, 2014, the EPA filed a consent decree requiring the EPA to take final action regarding the proposed regulation of coal combustion residuals as solid waste by December 19, 2014.

While the ultimate outcome of this matter cannot be determined at this time and will depend on the final form of any rules adopted and the outcome of any legal challenges, additional regulation of coal combustion residuals could have a material impact on the generation, management, beneficial use, and disposal of such residuals. Any material changes are likely to result in substantial additional compliance, operational, and capital costs that could affect future unit retirement and replacement decisions. Moreover, the traditional operating companies could incur additional material asset retirement obligations with respect to closing existing storage facilities. Southern Company's results of operations, cash flows, and financial condition could be significantly impacted if such costs are not recovered through regulated rates. Further, higher costs that are recovered through regulated rates could contribute to reduced demand for electricity, which could negatively impact results of operations, cash flows, and financial condition.

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 properties. The traditional operating companies conduct studies to determine the extent of any required cleanup and have recognized in their respective 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
The EPA currently regulates greenhouse gases under the Prevention of Significant Deterioration and Title V operating permit programs of the Clean Air Act. The legal basis for these regulations is currently being challenged in the U.S. Supreme Court. In addition, over the past several years, the U.S. Congress has considered many proposals to reduce greenhouse gas emissions,

mandate renewable or clean energy, and impose energy efficiency standards. Such proposals are expected to continue to be considered by the U.S. Congress. International climate change negotiations under the United Nations Framework Convention on Climate Change are also continuing.

On January 8, 2014, the EPA published re-proposed regulations to establish standards of performance for greenhouse gas emissions from new fossil fuel steam electric generating units. A Presidential memorandum issued on June 25, 2013 also directs the EPA to propose standards, regulations, or guidelines for addressing modified, reconstructed, and existing steam electric generating units by June 1, 2014.

Although the outcome of any federal, state, and international initiatives, including the EPA's proposed regulations and guidelines discussed above, will depend on the scope and specific requirements of the proposed and final rules and the outcome of any legal challenges and, therefore, cannot be determined at this time, additional restrictions on the Southern Company system's greenhouse gas emissions or requirements relating to renewable energy or energy efficiency at the federal or state level could result in significant additional compliance costs, including capital expenditures. These costs could affect future unit retirement and replacement decisions and could result in the retirement of additional coal-fired generating units. Also, additional compliance costs and costs related to unit retirements could affect results of operations, cash flows, and financial condition if such costs are not recovered through regulated rates or through market-based contracts. Further, higher costs that are recovered through regulated rates could contribute to reduced demand for electricity, which could negatively impact results of operations, cash flows, and financial condition.

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 2012 greenhouse gas emissions were approximately 99 million metric tons of CO_2 equivalent. The preliminary estimate of the Southern Company system's 2013 greenhouse gas emissions on the same basis is approximately 103 million metric tons of CO_2 equivalent. The level of greenhouse gas emissions from year to year will depend on the level of generation and mix of fuel sources and other factors.

PSC Matters

Alabama Power

Retail Rate Adjustments

In 2011, the Alabama PSC issued an order to eliminate a tax-related adjustment under Alabama Power's rate structure effective with October 2011 billings. The elimination of this adjustment resulted in additional revenues of approximately $31 million for 2011. In accordance with the order, Alabama Power made additional accruals to the NDR in the fourth quarter 2011 of an amount equal to such additional 2011 revenues. The NDR was impacted as a result of operations and maintenance expenses incurred in connection with the 2011 storms in Alabama. See "Natural Disaster Reserve" below for additional information. The elimination of this adjustment resulted in additional revenues of approximately $106 million for 2012.

Rate RSE

Alabama Power operates under a rate stabilization and equalization plan (Rate RSE) approved by the Alabama PSC. Alabama Power's Rate RSE adjustments are based on forward-looking information for the applicable upcoming calendar year. Rate 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 equity return range, customer refunds will be required; however, there is no provision for additional customer billings should the actual retail return fall below the allowed equity return range. Prior to 2014, retail rates remained unchanged when the retail return on common equity (ROE) was projected to be between 13.0% and 14.5%.

During 2013, the Alabama PSC held public proceedings regarding the operation and utilization of Rate RSE. On August 13, 2013, the Alabama PSC voted to issue a report on Rate RSE that found that Alabama Power's Rate RSE mechanism continues to be just and reasonable to customers and Alabama Power, but recommended Alabama Power modify Rate RSE as follows:

- Eliminate the provision of Rate RSE establishing an allowed range of ROE.
- Eliminate the provision of Rate RSE limiting Alabama Power's capital structure to an allowed equity ratio of 45%.
- Replace these two provisions with a provision that establishes rates based upon an allowed weighted cost of equity (WCE) range of 5.75% to 6.21%, with an adjusting point of 5.98%. If calculated under the previous Rate RSE provisions, the resulting WCE would range from 5.85% to 6.53%, with an adjusting point of 6.19%.

- Provide 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.

Substantially all other provisions of Rate RSE were unchanged.

On August 21, 2013, Alabama Power filed its consent to these recommendations with the Alabama PSC. The changes became effective for calendar year 2014. On November 27, 2013, Alabama Power made its Rate RSE submission to the Alabama PSC of projected data for calendar year 2014; projected earnings were within the specified WCE range and, therefore, retail rates under Rate RSE remained unchanged for 2014. In 2012 and 2013, retail rates under Rate RSE remained unchanged from 2011. Under the terms of Rate RSE, the maximum possible increase for 2015 is 5.00%.

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 certificated new plant (Rate CNP). Alabama Power may also recover retail costs associated with certificated PPAs under rate certificated new plant (Rate CNP PPA). There was no adjustment to Rate CNP PPA in 2012. On March 5, 2013, 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, 2013 through March 31, 2014. It is anticipated that no adjustment will be made to Rate CNP PPA in 2014. As of December 31, 2013, Alabama Power had an under recovered certificated PPA balance of $18 million, all of which is included in deferred under recovered regulatory clause revenues in the balance sheet.

In 2011, the Alabama PSC approved and certificated a PPA of approximately 200 MWs of energy from wind-powered generating facilities which became operational in December 2012. In September 2012, the Alabama PSC approved and certificated a second wind PPA of approximately 200 MWs which became operational in January 2014. The terms of the wind PPAs permit Alabama Power to use the energy and retire the associated environmental attributes in service of its customers or to sell environmental attributes, separately or bundled with energy. Alabama Power has elected the normal purchase normal sale (NPNS) scope exception under the derivative accounting rules for its two wind PPAs, which total approximately 400 MWs. The NPNS exception allows the PPAs to be recorded at a cost, rather than fair value, basis. The industry's application of the NPNS exception to certain physical forward transactions in nodal markets is currently under review by the U.S. Securities and Exchange Commission (SEC) at the request of the electric utility industry. The outcome of the SEC's review cannot now be determined. If Alabama Power is ultimately required to record these PPAs at fair value, an offsetting regulatory asset or regulatory liability will be recorded.

Rate CNP Environmental also allows for the recovery of Alabama Power's retail costs associated with environmental laws, regulations, or other such mandates. Rate CNP Environmental is based on forward-looking information and provides for the recovery of these costs pursuant to a factor that is calculated annually. Environmental costs to be recovered include operations and maintenance expenses, depreciation, and a return on certain invested capital. There was no adjustment to Rate CNP Environmental in 2012 or 2013. On August 13, 2013, the Alabama PSC approved Alabama Power's petition requesting a revision to Rate CNP Environmental that allows recovery of costs related to pre-2005 environmental assets previously being recovered through Rate RSE. The revenue impact as a result of this revision is estimated to be $58 million in 2014. On November 21, 2013, Alabama Power submitted calculations associated with its cost of complying with environmental mandates, as provided under Rate CNP Environmental. The filing reflected a projected unrecovered retail revenue requirement for environmental compliance of approximately $72 million, which is to be recovered in the billing months of January 2014 through December 2014. On December 3, 2013, the Alabama PSC issued a consent order that Alabama Power leave in effect for 2014 the factors associated with Alabama Power's environmental compliance costs for the year 2013. Any unrecovered amounts associated with 2014 will be reflected in the 2015 filing. As of December 31, 2013, Alabama Power had an under recovered environmental clause balance of $7 million which is included in deferred under recovered regulatory clause revenues in the balance sheet.

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 would be amortized over the affected unit's remaining useful life, as established prior to the decision regarding early retirement. See "Environmental Matters – Environmental Statutes and Regulations" herein for additional information regarding environmental regulations.

Compliance and Pension Cost Accounting Order

In November 2012, the Alabama PSC approved an accounting order to defer to a regulatory asset account certain compliance-related operations and maintenance expenditures for the years 2013 through 2017, as well as the incremental increase in operations expense related to pension cost for 2013. These deferred costs are to be amortized over a three-year period beginning in January 2015. The compliance related expenditures were related to (i) standards addressing Critical Infrastructure Protection issued by the North American Electric Reliability Corporation, (ii) cyber security requirements issued by the U.S. Nuclear Regulatory Commission (NRC), and (iii) NRC guidance addressing the readiness at nuclear facilities within the U.S. for severe events. The compliance-related expenses to be afforded regulatory asset treatment over the five-year period are currently estimated to be approximately $37 million. The amount of operations and maintenance expenses deferred to a regulatory asset in 2013 associated with compliance-related expenditures and pension cost was approximately $8 million and $12 million, respectively. Pursuant to the accounting order, Alabama Power has the ability to accelerate the amortization of the regulatory assets with notification to the Alabama PSC. See "Other Matters" herein for information regarding NRC actions as a result of the earthquake and tsunami that struck Japan in 2011.

Natural Disaster Reserve

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 Natural Disaster Reserve (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.

In accordance with the order that was issued by the Alabama PSC in 2011 to eliminate a tax-related adjustment under Alabama Power's rate structure that resulted in additional revenues, Alabama Power made additional accruals to the NDR in the fourth quarter 2011 of an amount equal to the additional 2011 revenues, which were approximately $31 million.

The accumulated balances in the NDR for the years ended December 31, 2013 and December 31, 2012 were approximately $96 million and $103 million, respectively. Any accruals to the NDR are included in the balance sheets under other regulatory liabilities, deferred and are reflected as other operations and maintenance expenses in the statements of income.

Nuclear Outage Accounting Order

In accordance with a 2010 Alabama PSC order, nuclear outage operations and maintenance expenses for the two units at Plant Farley are deferred to a regulatory asset when the charges actually occur and are then amortized over the subsequent 18-month operational cycle.

Approximately $31 million of nuclear outage costs from the spring of 2012 was amortized to nuclear operations and maintenance expenses over the 18-month period ended in December 2013. During the spring of 2013, approximately $28 million of nuclear outage costs was deferred to a regulatory asset, and beginning in July 2013, these deferred costs are being amortized over an 18-month period. During the fall of 2013, approximately $32 million of nuclear outage costs associated with the second unit was deferred to a regulatory asset, and beginning in January 2014, these deferred costs are being amortized over an 18-month period. Alabama Power will continue the pattern of deferral of nuclear outage expenses as incurred and the recognition of expenses over a subsequent 18-month period pursuant to the Alabama PSC order.

Non-Nuclear Outage Accounting Order

On August 13, 2013, the Alabama PSC approved Alabama Power's petition requesting authorization to defer to a regulatory asset account certain operations and maintenance expenses associated with planned outages at non-nuclear generation facilities in 2014 and to amortize those expenses over a three-year period beginning in 2015. The 2014 outage expenditures to be deferred and amortized are estimated to total approximately $78 million.

Georgia Power

Rate Plans

In 2010, the Georgia PSC approved an Alternate Rate Plan for the years 2011 through 2013 (2010 ARP), which resulted in base rate increases of approximately $562 million, $17 million, $125 million, and $74 million effective January 1, 2011, January 1, 2012, April 1, 2012, and January 1, 2013, respectively.

On December 17, 2013, the Georgia PSC voted to approve the Alternate Rate Plan for Georgia Power which became effective January 1, 2014 and continues through December 31, 2016 (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, which was filed with the Georgia PSC on November 18, 2013.

On January 1, 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 an additional $25 million; (3) Demand-Side Management (DSM) tariffs by an additional $1 million; and (4) Municipal Franchise Fee (MFF) tariff by an additional $4 million, for a total increase in base revenues of approximately $110 million.

Under the 2013 ARP, the following additional rate adjustments will be made to Georgia Power’s tariffs in 2015 and 2016 based on annual compliance filings to be made at least 90 days prior to the effective date of the tariffs:

- Effective January 1, 2015 and 2016, the traditional base tariff rates will increase by an estimated $101 million and $36 million, respectively, to recover additional generation capacity-related costs;
- Effective January 1, 2015 and 2016, the ECCR tariff will increase by an estimated $76 million and $131 million, respectively, to recover additional environmental compliance costs;
- Effective January 1, 2015, the DSM tariffs will increase by an estimated $6 million and decrease by an estimated $1 million effective January 1, 2016; and
- The MFF tariff will increase consistent with these adjustments.

Georgia Power currently estimates these adjustments will result in base revenue increases of approximately $187 million in 2015 and $170 million in 2016. The estimated traditional base tariff rate increases for 2015 and 2016 do not include additional Qualifying Facility (QF) PPA expenses; however, compliance filings will include QF PPA expenses for those facilities that are projected to provide capacity to Georgia Power during the following year.

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. However, if at any time during the term of the 2013 ARP, Georgia Power projects that its retail earnings will be below 10.00% for any calendar year, it may petition the Georgia PSC for implementation of the Interim Cost Recovery (ICR) tariff that would be used to adjust Georgia Power’s earnings back to a 10.00% retail ROE. The Georgia PSC would have 90 days to rule on Georgia Power’s request. The ICR tariff will expire at the earlier of January 1, 2017 or the end of the calendar year in which the ICR tariff becomes effective. In lieu of requesting implementation of an ICR tariff, or if the Georgia PSC chooses not to implement the ICR tariff, Georgia Power may file a full rate case.

Except as provided above, Georgia Power will not file for a general base rate increase while the 2013 ARP is in effect. Georgia Power is required to file a general 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 Plans

See "Environmental Matters – Environmental Statutes and Regulations – Air Quality," "– Water Quality," and "– Coal Combustion Residuals" 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 regulation of coal combustion residuals; the State of Georgia's Multi-Pollutant Rule; 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; and Georgia Power's latest triennial Integrated Resource Plan as approved by the Georgia PSC (2013 IRP).

On January 31, 2013, Georgia Power filed its 2013 IRP. The filing included Georgia Power's request to decertify 16 coal- and oil-fired units totaling 2,093 MWs. Several factors, including the cost to comply with existing and future environmental regulations, recent and forecasted economic conditions, and lower natural gas prices, contributed to the decision to close these units.

On April 17, 2013, the Georgia PSC approved the decertification of Plant Bowen Unit 6 (32 MWs), which was retired on April 25, 2013. On September 30, 2013, Plant Branch Unit 2 (319 MWs) was retired as approved by the Georgia PSC in the 2011 Integrated Resource Plan Update (2011 IRP Update) in order to comply with the State of Georgia's Multi-Pollutant Rule.

On July 11, 2013, the Georgia PSC approved Georgia Power's request to decertify and retire Plant Boulevard Units 2 and 3 (28 MWs) effective July 17, 2013. Plant Branch Units 3 and 4 (1,016 MWs), Plant Yates Units 1 through 5 (579 MWs), and Plant McManus Units 1 and 2 (122 MWs) will be decertified and retired by April 16, 2015, the compliance date of the MATS rule. The decertification date of Plant Branch Unit 1 was extended from December 31, 2013 as specified in the final order in the 2011 IRP Update to coincide with the decertification date of Plant Branch Units 3 and 4. The decertification and retirement of Plant Kraft Units 1 through 4 (316 MWs) was also approved and will be effective by April 16, 2016, based on a one-year extension of the MATS rule compliance date that was approved by the State of Georgia Environmental Protection Division on September 10, 2013 to allow for necessary transmission system reliability improvements.

Additionally, the Georgia PSC approved Georgia Power's proposed MATS rule compliance plan for emissions controls necessary for the continued operation of Plants Bowen Units 1 through 4, Wansley Units 1 and 2, Scherer Units 1 through 3, and Hammond Units 1 through 4, the switch to natural gas as the primary fuel at Plant Yates Units 6 and 7 and SEGCO's Plant Gaston Units 1 through 4, as well as the fuel switch at Plant McIntosh Unit 1 to operate on Powder River Basin coal.

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 beginning in January 2014 and the amortization of any 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. The Georgia PSC deferred a decision regarding the appropriate recovery period for the costs associated with unusable materials and supplies remaining at the retiring plants to Georgia Power's next base rate case, which Georgia Power expects to file in 2016 (2016 Rate Case). In the 2013 IRP, the Georgia PSC also deferred decisions regarding the recovery of any fuel related costs that could be incurred in connection with the retirement units to be addressed in future fuel cases.

A request was filed with the Georgia PSC on January 10, 2014 to cancel the proposed biomass fuel conversion of Plant Mitchell Unit 3 (155 MWs) because it would not be cost effective for customers. The filing also notified the Georgia PSC of Georgia Power’s plans to seek decertification later this year. Plant Mitchell Unit 3 will continue to operate as a coal unit until April 2015 when it will be required to cease operation or install additional environmental controls to comply with the MATS rule. In connection with the retirement decision, Georgia Power reclassified the retail portion of the net carrying value of Plant Mitchell Unit 3 from plant in service, net of depreciation, to other utility plant, net.

The decertification of these units and fuel conversions are not expected to have a material impact on Southern Company's financial statements; however, the ultimate outcome depends on the Georgia PSC's order in the 2016 Rate Case and future fuel cases and cannot be determined at this time.

Renewables Development

On December 17, 2013, four PPAs totaling 50 MWs of utility scale solar generation under the Georgia Power Advanced Solar Initiative (GPASI) were approved by the Georgia PSC, with Georgia Power as the purchaser. These contracts will begin in 2015 and end in 2034. The resulting purchases will be for energy only and recovered through Georgia Power's fuel cost recovery mechanism. Under the 2013 IRP, the Georgia PSC approved an additional 525 MWs of solar generation to be purchased by Georgia Power. The 525 MWs will be divided into 425 MWs of utility scale projects and 100 MWs of distributed generation.

On November 4, 2013, Georgia Power filed an application for the certification of two PPAs which were executed on April 22, 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.

During 2013, Georgia Power executed four PPAs to purchase a total of 169 MWs of biomass capacity and energy from four facilities in Georgia that will begin in 2015 and end in 2035. On May 21, 2013, the Georgia PSC approved two of the biomass PPAs and the remaining two were approved on December 17, 2013. The four biomass PPAs are contingent upon the counterparty meeting specified contract dates for posting collateral and commercial operation. The ultimate outcome of this matter cannot be determined at this time.

Storm Damage Recovery

Georgia Power defers and recovers certain costs related to damages from major storms as mandated by the Georgia PSC. As of December 31, 2013, the balance in the regulatory asset related to storm damage was $37 million. As a result of this regulatory treatment, the costs related to storms are generally not expected to have a material impact on Southern Company's financial statements.

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 any cash flow. The traditional operating companies continuously monitor their under or over recovered fuel cost balances. At December 31, 2013, total over recovered fuel costs in the balance sheets of Alabama Power, Georgia Power, and Mississippi Power were approximately $115 million, and total under recovered fuel costs in the balance sheet of Gulf Power were approximately $21 million. The lower cost of natural gas resulted in total over recovered fuel costs in the balance sheets of Georgia Power, Gulf Power, and Mississippi Power of approximately $303 million at December 31, 2012. Total under recovered fuel costs were approximately $4 million in the balance sheet of Alabama Power at December 31, 2012.

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

Income Tax Matters

Bonus Depreciation

On January 2, 2013, the American Taxpayer Relief Act of 2012 (ATRA) was signed into law. The ATRA retroactively extended several tax credits through 2013 and extended 50% bonus depreciation for property placed in service in 2013 (and for certain long-term production-period projects to be placed in service in 2014, including the Kemper IGCC). The extension of 50% bonus depreciation had a positive impact on Southern Company's cash flows of approximately $440 million in 2013 and is expected to have a positive impact between $650 million and $720 million on the cash flows of Southern Company in 2014. See Note 3 under "Integrated Coal Gasification Combined Cycle" for additional information on factors which could result in changes to the scheduled in-service date of the Kemper IGCC and result in the loss of the tax benefits related to bonus depreciation.

Construction Program

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 approvals 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 $6.1 billion, $5.4 billion, and $4.5 billion for 2014, 2015, and 2016, 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 two units, each with approximately 1,100 MWs) and the 582-MW Kemper IGCC (in which Mississippi Power is ultimately expected to hold an 85% ownership interest). See Note 3 to the financial statements under "Retail Regulatory Matters – Georgia Power – Nuclear Construction" and "Integrated Coal Gasification Combined Cycle" for additional information.

In 2013, the Company incurred pre-tax charges of $1.2 billion ($729 million after-tax) for revisions of estimated costs expected to be incurred on Mississippi Power's construction of the Kemper IGCC above the $2.88 billion cost cap established by the Mississippi PSC, net of the DOE Grants and excluding the Cost Cap Exceptions. 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 will be reflected in the Company's statements of income and these changes could be material. Additionally, there are certain risks associated with the construction program in general and certain risks associated with the licensing, construction, and operation of nuclear generating units in particular, including potential impacts that could result from a major incident at a nuclear facility anywhere in the world. The ultimate outcome of these events 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 increased generally throughout the U.S. In particular, personal injury, property damage, and other claims for damages alleged to have been caused by CO_2 and other emissions, coal combustion residuals, and alleged exposure to hazardous materials, and/or requests for injunctive relief in connection with such matters, have become more frequent.

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.

In 2011, a major earthquake and tsunami struck Japan and caused substantial damage to the nuclear generating units at the Fukushima Daiichi generating plant. The events in Japan have created uncertainties that may affect future costs for operating nuclear plants. Specifically, the NRC is performing additional operational and safety reviews of nuclear facilities in the U.S., which could potentially impact future operations and capital requirements. In addition, the NRC has issued a series of orders requiring safety-related changes to U.S. nuclear facilities and expects to issue orders in the future requiring additional upgrades. The final form and the resulting impact of any changes to safety requirements for nuclear reactors will be dependent on further review and action by the NRC and cannot be determined at this time; however, management does not currently anticipate that the compliance costs associated with these orders would have a material impact on Southern Company's financial statements.

See "PSC Matters – Alabama Power – Compliance and Pension Cost Accounting Order" herein for additional information on Alabama Power's PSC approved accounting order, which allows the deferral of certain compliance-related operations and maintenance expenditures related to compliance with the NRC guidance.

Additionally, there are certain risks associated with the licensing, construction, and operation of nuclear generating units, including potential impacts that could result from a major incident at a nuclear facility anywhere in the world. The ultimate outcome of these events cannot be determined at this time.

On April 4, 2013, an explosion occurred at Plant Bowen Unit 2 that resulted in substantial damage to the Plant Bowen Unit 2 generator, the Plant Bowen Units 1 and 2 control room and surrounding areas, and Plant Bowen's switchyard. Plant Bowen Unit 1 (approximately 700 MWs) was returned to service on August 4, 2013 and Plant Bowen Unit 2 (approximately 700 MWs) was returned to service on December 20, 2013. Georgia Power expects that any material repair costs related to the damage will be covered by property insurance.

On November 19, 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. In accordance with the court’s order, the DOE has submitted a proposal to the U.S. Congress to change the fee to zero. That proposal is pending before the U.S. Congress and will become effective after 90 days of legislative session from the time of submittal unless the U.S. Congress enacts legislation that impacts the proposed fee change. The DOE’s petition for rehearing of the November 2013 decision is currently pending and Alabama Power and Georgia Power are continuing to pay the fee of approximately $13 million and $15 million annually, respectively, based on their ownership interest. 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 2013, 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. 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, asset retirement obligations, 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.

Contingent Obligations

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

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 in accordance with GAAP 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 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. Southern Company discounts the future cash flows related to its postretirement benefit plans 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.

MANAGEMENT'S DISCUSSION AND ANALYSIS (continued)
Southern Company and Subsidiary Companies 2013 Annual Report

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 2014	Increase/(Decrease) in Projected Obligation for Pension Plan at December 31, 2013	Increase/(Decrease) in Projected Obligation for Other Postretirement Benefit Plans at December 31, 2013
		(in millions)	
25 basis point change in discount rate	$27/$(26)	$296/$(281)	$49/$(47)
25 basis point change in salaries	$16/$(15)	$80/$(77)	$–/$–
25 basis point change in long-term return on plan assets	$22/$(22)	N/A	N/A

N/A – Not applicable

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

Mississippi Power estimates the scheduled in-service date for the Kemper IGCC to be the fourth quarter 2014 and has revised its cost estimate to complete construction above the $2.88 billion cost cap, net of the DOE Grants and excluding the Cost Cap Exceptions. Mississippi Power does not intend to seek rate recovery or any joint owner contributions for any related costs 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 pretax charges of $1.2 billion in 2013. 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 will be reflected in Southern Company's statements of income and these changes could be material. Mississippi Power could experience further construction cost increases and/or schedule extensions with respect to the Kemper IGCC as a result of 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, or non-performance under construction or other agreements. Furthermore, Mississippi Power could also experience further schedule extensions associated with start-up activities for this "first-of-a-kind" technology, including major equipment failure, system integration, and operations, and/or unforeseen engineering problems, which would result in further cost increases.

Given the significant judgment involved in estimating the future costs to complete construction, 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.

FINANCIAL CONDITION AND LIQUIDITY

Overview

Although earnings in 2013 were negatively affected by revisions to the cost estimate for the Kemper IGCC, Southern Company's financial condition remained stable at December 31, 2013. These charges for the year ended December 31, 2013 have resulted in cash expenditures of $375.1 million with no recovery as of December 31, 2013 and are expected to result in future cash expenditures (primarily in 2014) of approximately $805 million with no recovery. Southern Company's cash requirements primarily consist of funding ongoing operations, common stock dividends, capital expenditures, and debt maturities. The Southern Company system's capital expenditures and other investing activities include investments to meet projected long-term demand requirements, 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 2014 through 2016, 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 equipment for existing generating 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 through debt and equity issuances. Southern Company intends to continue to monitor its access to short-term and long-term capital markets as well as its bank credit arrangements to meet future capital and liquidity needs. See "Sources of Capital," "Financing Activities," and "Capital Requirements and Contractual Obligations" herein for additional information.

Southern Company's investments in the qualified pension plan and the nuclear decommissioning trust funds increased in value as of December 31, 2013 as compared to December 31, 2012. No contributions to the qualified pension plan were made for the year ended December 31, 2013. No mandatory contributions to the qualified pension plan are anticipated for the year ending December 31, 2014.

Net cash provided from operating activities in 2013 totaled $6.1 billion, an increase of $1.2 billion from 2012. The most significant change in operating cash flow for 2013 as compared to 2012 was a decrease in fossil fuel stock due to an increase in KWH generation. Net cash provided from operating activities in 2012 totaled $4.9 billion, a decrease of $1.0 billion from 2011. Significant changes in operating cash flow for 2012 as compared to 2011 include an increase in fossil fuel stock and contributions to the qualified pension plan.

Net cash used for investing activities in 2013, 2012, and 2011 totaled $5.7 billion, $5.2 billion, and $4.2 billion, respectively. The cash used for investing activities for each of these years was primarily for property additions to utility plant.

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. Net cash used for financing activities totaled $417 million in 2012 due to redemptions of long-term debt, the repurchase of common stock, and payments of common stock dividends, partially offset by issuances of long-term debt. Fluctuations in cash flow from financing activities vary from year to year based on capital needs and the maturity or redemption of securities.

Significant balance sheet changes in 2013 include an increase of $2.8 billion in total property, plant, and equipment for the installation of equipment to comply with environmental standards and construction of generation, transmission, and distribution facilities. Other significant changes include a decrease in other regulatory assets, deferred of $1.5 billion and a decrease in employee benefit obligations of $1.1 billion, both of which are primarily attributable to a positive return on assets and an increase in the discount rate associated with retirement benefit plans.

At the end of 2013, the market price of Southern Company's common stock was $41.11 per share (based on the closing price as reported on the New York Stock Exchange) and the book value was $21.43 per share, representing a market-to-book value ratio of 192%, compared to $42.81, $21.09, and 203%, respectively, at the end of 2012.

Sources of Capital

Southern Company intends to meet its future capital needs through internal cash flow 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 to be raised in 2014, as well as in subsequent years, will be contingent on Southern Company's investment opportunities and 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 sources similar to those used in the past, which were primarily from operating cash flows, security issuances, term loans, short-term borrowings, and equity contributions from Southern Company. However, the amount, type, and timing of any future financings, if needed, will depend upon prevailing market conditions, regulatory approval, and other factors.

On February 20, 2014, Georgia Power and the DOE entered into a loan guarantee agreement (Loan Guarantee Agreement), pursuant to which the DOE agreed to guarantee borrowings to be made by Georgia Power under a multi-advance credit facility (FFB Credit Facility) among Georgia Power, the DOE, and the Federal Financing Bank (FFB). Georgia Power's reimbursement obligations to the DOE are secured by a first priority lien on (i) Georgia Power's 45.7% undivided ownership interest in Plant Vogtle Units 3 and 4 and (ii) Georgia Power's rights and obligations under the principal contracts relating to Plant Vogtle Units 3 and 4. Under the FFB Credit Facility, Georgia Power may make term loan borrowings through the FFB. Proceeds of borrowings made under the FFB Credit Facility will 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). 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. See Note 6 to the financial statements for additional information.

In addition, Mississippi Power received $245 million of DOE Grants that were used for the construction of the Kemper IGCC. An additional $25 million of DOE Grants is expected to be received for the initial 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.

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 Southern 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.

Southern Company's current liabilities frequently exceed current assets because of the continued use of short-term debt as a funding source to meet scheduled maturities of long-term debt, as well as cash needs, which can fluctuate significantly due to the seasonality of the business of the Southern Company system. To meet short-term cash needs and contingencies, Southern Company has substantial cash flow from operating activities and access to capital markets, including commercial paper programs which are backed by bank credit facilities.

At December 31, 2013, Southern Company and its subsidiaries had approximately $659 million of cash and cash equivalents. Committed credit arrangements with banks at December 31, 2013 were as follows:

	Expires[(a)]						Executable Term Loans		Due Within One Year	
Company	2014	2015	2016	2018	Total	Unused	One Year	Two Years	Term Out	No Term Out
	(in millions)				(in millions)		(in millions)		(in millions)	
Southern Company	$—	$—	$—	$1,000	$1,000	$1,000	$—	$—	$—	$—
Alabama Power	238	35	—	1,030	1,303	1,303	53	—	53	185
Georgia Power	—	—	150	1,600	1,750	1,736	—	—	—	—
Gulf Power	110	—	165	—	275	275	45	—	45	65
Mississippi Power	135	—	165	—	300	300	25	40	65	70
Southern Power	—	—	—	500	500	500	—	—	—	—
Other	75	25	—	—	100	100	25	—	25	50
Total	$558	$60	$480	$4,130	$5,228	$5,214	$148	$40	$188	$370

(a) No credit arrangements expire in 2017.

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

A portion of the unused credit with banks is allocated to provide liquidity support to the traditional operating companies' variable rate 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, 2013 was approximately $1.8 billion. In addition, at December 31, 2013, the traditional operating companies had $442 million of fixed rate pollution control revenue bonds that will be required to be remarketed within the next 12 months.

Southern Company and its subsidiaries expect to renew their credit arrangements as needed, prior to expiration. Most of these arrangements contain covenants that limit debt levels and contain 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. Southern Company, the traditional operating companies, and Southern Power are currently in compliance with all such covenants. None of the arrangements contain material adverse change clauses at the time of borrowings.

Southern Company, the traditional operating companies, and Southern Power make short-term borrowings primarily through commercial paper programs that have the liquidity support of committed bank credit arrangements. Southern

Company, the traditional operating companies, and Southern Power may also borrow through various other arrangements with banks. Commercial paper and short-term bank loans are included in notes payable in the balance sheets.

Details of short-term borrowings were as follows:

	Short-term Debt at the End of the Period(a)		Short-term Debt During the Period [b]		
	Amount Outstanding (in millions)	Weighted Average Interest Rate	Average Outstanding (in millions)	Weighted Average Interest Rate	Maximum Amount Outstanding (in millions)
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 %	
December 31, 2012:					
Commercial paper	$820	0.3 %	$550	0.3 %	$938
Short-term bank debt	—	— %	116	1.2 %	300
Total	$820	0.3 %	$666	0.5 %	
December 31, 2011:					
Commercial paper	$654	0.3 %	$697	0.3 %	$1,586
Short-term bank debt	200	1.2 %	14	1.2 %	200
Total	$854	0.5 %	$711	0.3 %	

(a) Excludes notes payable related to other energy service contracts of $5 million and $6 million at December 31, 2012 and 2011, respectively.

(b) Average and maximum amounts are based upon daily balances during the twelve-month periods ended December 31, 2013, 2012, and 2011.

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

Financing Activities

During 2013, Southern Company issued approximately 6.9 million shares of common stock for approximately $222.4 million through the employee and director stock plans, of which 0.7 million shares related to Southern Company's performance share plan.

During the first seven months of 2013, all sales under the Southern Investment Plan and the employee savings plan were funded with shares acquired on the open market by the independent plan administrators. Beginning in August 2013 and continuing through the fourth quarter 2013, Southern Company began using shares held in treasury to satisfy the requirements under the Southern Investment Plan and the employee savings plan, issuing a total of approximately 4.4 million shares of common stock previously held in treasury for approximately $183.6 million.

In addition, during the last six months of 2013, Southern Company issued approximately 8.0 million shares of common stock through at-the-market issuances pursuant to sales agency agreements related to Southern Company’s continuous equity offering program and received cash proceeds of approximately $327.3 million, net of $2.8 million in fees and commissions.

In June 2013, Gulf Power issued 500,000 shares of Series 2013A 5.60% Preference Stock and realized proceeds of $50 million. The proceeds from the sale of the Preference Stock, together with the proceeds from the issuance of the $90 million aggregate principal amount of Gulf Power's Series 2013A 5.00% Senior Notes reflected in the table below, were used to repay at maturity $60 million aggregate principal amount of Gulf Power's Series G 4.35% Senior Notes due July 15, 2013, to repay a portion of a 90-day floating rate bank loan in an aggregate principal amount outstanding of $125 million, for a portion of the redemption in July 2013 of $30 million aggregate principal amount outstanding of Gulf Power’s Series H 5.25% Senior Notes due July 15, 2033, and for general corporate purposes, including Gulf Power’s continuous construction program.

MANAGEMENT'S DISCUSSION AND ANALYSIS (continued)
Southern Company and Subsidiary Companies 2013 Annual Report

The following table outlines the long-term debt financing activities for Southern Company and its subsidiaries for the year ended December 31, 2013:

Company	Senior Note Issuances	Senior Note Redemptions and Maturities	Revenue Bond Issuances	Revenue Bond Redemptions and Maturities	Other Long-Term Debt Issuances	Other Long-Term Debt Redemptions and Maturities
			(in millions)			
Southern Company	$500	$—	$—	$—	$—	$—
Alabama Power	300	250	—	—	—	—
Georgia Power	850	1,775	194	194	—	—
Gulf Power	90	90	—	—	—	—
Mississippi Power	—	50	—	—	517	208
Southern Power	300	—	—	—	23	9
Other	100	50	—	—	—	—
Total	$2,140	$2,215	$194	$194	$540	$217

In August 2013, Southern Company issued $500 million aggregate principal amount of Series 2013A 2.45% Senior Notes due September 1, 2018. The proceeds were used to pay a portion of Southern Company’s outstanding short-term indebtedness and for other general corporate purposes.

Southern Company's subsidiaries used the proceeds of the debt issuances shown in the table above for the redemptions and maturities shown in the table above, to repay short-term indebtedness, and for general corporate purposes, including their respective continuous construction programs.

Mississippi Power's "Other Long-Term Debt Issuances" reflected in the table above include $11 million related to an agreement entered into by the Mississippi Business Finance Corporation (MBFC) in November 2013 for the issuances of up to $45 million of taxable revenue bonds for the benefit of Mississippi Power. During 2013, the MBFC issued $11 million of taxable revenue bonds under the agreement, the proceeds of which were used by Mississippi Power for the cost of the acquisition, construction, equipping, installation, and improvement of certain equipment and facilities for the lignite mining facility relating to the Kemper IGCC. Any future issuances under the agreement will be used for the same purposes.

In March 2013, Georgia Power entered into three 60-day floating rate bank loans bearing interest based on one-month London Interbank Offered Rate (LIBOR). Each of these short-term loans was for $100 million aggregate principal amount and the proceeds were used for working capital and other general corporate purposes, including Georgia Power's continuous construction program. These bank loans were repaid at maturity.

In June 2013, Gulf Power entered into a 90-day floating rate bank loan bearing interest based on one-month LIBOR. This short-term loan was for $125 million aggregate principal amount and the proceeds were used for working capital and other general corporate purposes, including Gulf Power’s continuous construction program. This bank loan was repaid in July 2013.

In November 2013, Georgia Power entered into three four-month floating rate bank loans for an aggregate principal amount of $400 million, bearing interest based on one-month LIBOR. The proceeds of these short-term loans were used for working capital and other general corporate purposes, including Georgia Power's continuous construction program. Subsequent to December 31, 2013, Georgia Power repaid these bank term loans.

The bank loans and the MBFC taxable revenue bonds have 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 other hybrid securities and, for Mississippi Power, securitized debt relating to the securitization of certain costs of the Kemper IGCC. At December 31, 2013, Georgia Power and Mississippi Power

were in compliance with their respective debt limits.
In addition, these bank loans and the MBFC taxable revenue bonds contain cross default provisions that would be triggered if the borrower defaulted on other indebtedness (including guarantee obligations) above a specified threshold. The cross default provisions are restricted to the indebtedness, including any guarantee obligations, of the company that has such bank loans. Georgia Power and Mississippi Power are currently in compliance with all such covenants.
Gulf Power purchased and held $42 million aggregate principal amount of Development Authority of Monroe County (Georgia) Pollution Control Revenue Bonds (Gulf Power Company Plant Scherer Project), First Series 2002 (First Series 2002 Bonds) and

$21 million aggregate principal amount of Development Authority of Monroe County (Georgia) Pollution Control Revenue Bonds (Gulf Power Company Plant Scherer Project), First Series 2010 (First Series 2010 Bonds) in May 2013 and June 2013, respectively. In June 2013, Gulf Power reoffered the First Series 2002 Bonds and the First Series 2010 Bonds to the public.

Also in November 2013, Georgia Power purchased and now holds $104.6 million aggregate principal amount of pollution control revenue bonds issued for its benefit in 2013. Georgia Power may reoffer these bonds to the public at a later date.

In December 2013, Gulf Power purchased and now holds $13 million aggregate principal amount of Mississippi Business Finance Corporation Solid Waste Disposal Facilities Revenue Refunding Bonds, Series 2012 (Gulf Power Company Project), which Gulf Power may reoffer to the public at a later date.

In September 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 inception of $83 million with an annual interest rate of 4.9%.

Subsequent to December 31, 2013, Mississippi Power entered into an 18-month floating rate bank loan bearing interest based on the one-month LIBOR. This term loan was for $250 million aggregate principal amount, and proceeds were used for working capital and other general corporate purposes, including Mississippi Power's continuous construction program.

Also subsequent to December 31, 2013, Mississippi Power received an additional $75 million interest-bearing refundable deposit from South Mississippi Electric Power Association (SMEPA) to be applied to the sale price for the pending sale of an undivided interest in the Kemper IGCC. See Note 3 to the financial statements under "Integrated Coal Gasification Combined Cycle – Proposed Sale of Undivided Interest to SMEPA" for additional information.

Subsequent to December 31, 2013, 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 February 20, 2044 (the final maturity date) and the interest rate applicable to the remaining $500 million is 3.488% for an interest period that extends to February 20, 2029 and will be reset from time to time thereafter through the final maturity date. The final maturity date for all advances under the FFB Credit Facility is February 20, 2044. The proceeds of the initial borrowings under the FFB Credit Facility were used to reimburse Georgia Power for Eligible Project Costs relating to the construction of Plant Vogtle Units 3 and 4. Georgia Power's reimbursement obligations to the DOE are secured by a first priority lien on (i) Georgia Power's 45.7% undivided ownership interest in Plant Vogtle Units 3 and 4 and (ii) Georgia Power's rights and obligations under the principal contracts relating to Plant Vogtle Units 3 and 4. See Note 6 to the financial statements for additional information.

Under the Loan Guarantee Agreement, Georgia Power is subject to customary events of default, as well as cross-defaults to other indebtedness and events of default relating to any failure to make payments under the engineering, procurement, and construction contract, as amended, relating to Plant Vogtle Units 3 and 4 or certain other agreements providing intellectual property rights for Plant Vogtle Units 3 and 4. The Loan Guarantee Agreement also includes events of default specific to the DOE loan guarantee program, including the failure of Georgia Power or Southern Nuclear Operating Company, Inc. to comply with requirements of law or DOE loan guarantee program requirements. See Note 6 to the financial statements under "DOE Loan Guarantee Borrowings" for additional information.

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 Baa2, or BBB- and/or Baa3 or below. These contracts are for physical electricity purchases and sales, fuel purchases, fuel transportation and storage, emissions allowances, energy price risk management, and construction of new generation.

MANAGEMENT'S DISCUSSION AND ANALYSIS (continued)
Southern Company and Subsidiary Companies 2013 Annual Report

The maximum potential collateral requirements under these contracts at December 31, 2013 were as follows:

Credit Ratings	Maximum Potential Collateral Requirements
	(in millions)
At BBB and Baa2	$9
At BBB- and/or Baa3	470
Below BBB- and/or Baa3	2,313

In March 2012 and subsequent to December 31, 2013, Mississippi Power received $150 million and $75 million, respectively, of 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. Until the sale is closed, the deposits bear interest at Mississippi Power's AFUDC rate adjusted for income taxes, which was 9.932% per annum for 2013 and 9.967% per annum for 2012, and are refundable to SMEPA upon termination of the asset purchase agreement related to such purchase, within 60 days of a request by SMEPA for a full or partial refund, or within 15 days at SMEPA's discretion in the event that Mississippi Power is assigned a senior unsecured credit rating of BBB+ or lower by Standard and Poor's Rating Services, a division of The McGraw Hill Companies, Inc. (S&P) or Baa1 or lower by Moody's Investors Service, Inc. (Moody's) or ceases to be rated by either of these rating agencies. On July 18, 2013, Southern Company entered into an agreement with SMEPA under which Southern Company has agreed to guarantee the obligations of Mississippi Power with respect to any required refund of the deposits.

On May 24, 2013, S&P revised the ratings outlook for Southern Company and the traditional operating companies from stable to negative.

On August 6, 2013, Moody's downgraded the senior unsecured debt and preferred stock ratings of Mississippi Power to Baa1 from A3 and to Baa3 from Baa2, respectively. Moody's maintained the stable ratings outlook for Mississippi Power.

On August 6, 2013, Fitch Ratings, Inc. affirmed the senior unsecured debt and preferred stock ratings of Mississippi Power and revised the ratings outlook for Mississippi Power from stable to negative.

On January 31, 2014, Moody's upgraded the senior unsecured debt and preferred stock ratings of Alabama Power to A1 from A2 and A3 from Baa1, respectively. Also on January 31, 2014, Moody's upgraded the senior unsecured debt and preferred stock ratings of Gulf Power to A2 from A3 and to Baa1 from Baa2, respectively. Moody's maintained the stable ratings outlook for Alabama Power and Gulf Power.

Generally, collateral may be provided by a Southern Company guaranty, letter of credit, or cash. Additionally, any credit rating downgrade could impact the ability of Southern Company and its subsidiaries to access capital markets, particularly the short-term debt market and the variable rate pollution control revenue bond market.

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 outstanding at December 31, 2013 have a notional amount of $350 million and are related to fixed and floating rate obligations which expire in 2014. The weighted average interest rate on $3.3 billion of long-term and short-term variable interest rate exposure that has not been hedged at January 1, 2014 was 0.70%. If Southern Company sustained a 100 basis point change in interest rates for all unhedged variable rate long-term debt and short-term bank loans, the change would affect annualized interest expense by approximately $33 million at January 1, 2014. 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 enter into physical fixed-price contracts for the purchase and sale of electricity through the wholesale electricity market and, to a lesser extent, financial hedge contracts for natural gas purchases. 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, 2013 when compared to the December 31, 2012 reporting period.

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

	2013 Changes	2012 Changes
	Fair Value (in millions)	
Contracts outstanding at the beginning of the period, assets (liabilities), net	$(85)	$(231)
Contracts realized or settled:		
Swaps realized or settled	43	167
Options realized or settled	19	39
Current period changes[(a)]:		
Swaps	2	(41)
Options	(11)	(19)
Contracts outstanding at the end of the period, assets (liabilities), net	$(32)	$(85)

(a) 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:

	2013	2012
	mmBtu* Volume (in millions)	
Commodity – Natural gas swaps	216	171
Commodity – Natural gas options	59	105
Total hedge volume	275	276

* million British thermal units (mmBtu)

The weighted average swap contract cost above market prices was approximately $0.10 per mmBtu as of December 31, 2013 and $0.39 per mmBtu as of December 31, 2012. 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, 2013 and 2012, substantially all of the Southern Company system's energy-related derivative contracts were designated as regulatory hedges and are 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 other comprehensive income 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, 2013 were as follows:

	Fair Value Measurements December 31, 2013			
	Total Fair Value	Maturity Year 1	Years 2&3	Years 4&5
	(in millions)			
Level 1	$—	$—	$—	$—
Level 2	(32)	(10)	(18)	(4)
Level 3	—	—	—	—
Fair value of contracts outstanding at end of period	$(32)	$(10)	$(18)	$(4)

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 be $6.1 billion for 2014, $5.4 billion for 2015, and $4.5 billion for 2016. Included in the estimated amount for 2014 are expenditures related to the construction of the Kemper IGCC of $490 million, which is net of SMEPA's 15% proposed ownership share of the Kemper IGCC of approximately $555 million in 2014 (including construction costs for all prior years relating to its proposed ownership interest). Capital expenditures to comply with environmental statutes and regulations included in these estimated amounts are $1.5 billion, $1.1 billion, and $600 million for 2014, 2015, and 2016, respectively. These amounts include capital expenditures related to contractual purchase commitments for nuclear fuel and capital expenditures covered under long-term service agreements.

Southern Company anticipates that the Southern Company system's capital expenditure requirements will continue to decline through the middle of the decade, before rising again to meet additional requirements for environmental compliance and new generation.

See FUTURE EARNINGS POTENTIAL – "Environmental Matters – Environmental Statutes and Regulations" herein for additional information.

The construction programs are subject to periodic review and revision, and actual construction costs may vary from these estimates because of numerous factors. These factors include: changes in business conditions; changes in load projections; changes in the expected environmental compliance program; 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 legislation; the cost and efficiency of construction labor, equipment, and materials; project scope and design changes; storm impacts; and the cost of capital. In addition, there can be no assurance that costs related to capital expenditures will be fully recovered. See Note 3 to the financial statements under "Retail Regulatory Matters – Georgia Power – Nuclear Construction" and "Integrated Coal Gasification Combined Cycle" for additional information.

Table of Contents Index to 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, and other purchase commitments 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.

Table of Contents Index to Financial Statements

MANAGEMENT'S DISCUSSION AND ANALYSIS (continued)
Southern Company and Subsidiary Companies 2013 Annual Report

Contractual Obligations

	2014	2015-2016	2017-2018 (in millions)	After 2018	Total
Long-term debt[(a)] —					
Principal	$440	$4,768	$2,001	$14,393	$21,602
Interest	805	1,509	1,297	10,235	13,846
Preferred and preference stock dividends[(b)]	68	136	136	—	340
Financial derivative obligations[(c)]	27	25	4	—	56
Operating leases[(d)]	101	140	75	135	451
Capital leases[(d)]	29	25	22	87	163
Unrecognized tax benefits[(e)]	7	—	—	—	7
Purchase commitments —					
Capital[(f)]	5,596	8,948	—	—	14,544
Fuel[(g)]	4,227	5,635	3,263	6,925	20,050
Purchased power[(h)]	295	740	788	4,163	5,986
Other[(i)]	267	419	435	967	2,088
Trusts —					
Nuclear decommissioning[(j)]	2	11	11	115	139
Pension and other postretirement benefit plans[(k)]	97	200	—	—	297
Total	$11,961	$22,556	$8,032	$37,020	$79,569

(a) All amounts are reflected based on final maturity dates. Southern Company and its subsidiaries plan to continue 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, 2014, 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) For additional information, see Notes 1 and 11 to the financial statements.

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

(e) 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 and compliance costs associated with environmental regulations. Estimates reflect the proposed sale of 15% of the Kemper IGCC to SMEPA. See Note 3 to the financial statements under "Integrated Coal Gasification Combined Cycle" for additional information. These amounts exclude contractual purchase commitments for nuclear fuel and capital expenditures covered under long-term service agreements which are reflected separately. At December 31, 2013, 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, 2013.

(h) Estimated minimum long-term obligations for various PPA purchases from gas-fired, biomass, and wind-powered facilities. A total of $1.3 billion of biomass PPAs is contingent upon the counterparty meeting specified contract dates for posting collateral and commercial operation. See Note 3 to the financial statements under "Retail Regulatory Matters – Georgia Power – Renewables Development" for additional information.

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

(j) Projections of nuclear decommissioning trust fund contributions are based on the 2010 ARP for 2014 and on the 2013 ARP thereafter for Georgia Power. 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.

MANAGEMENT'S DISCUSSION AND ANALYSIS (continued)
Southern Company and Subsidiary Companies 2013 Annual Report

Cautionary Statement Regarding Forward-Looking Statements
Southern Company's 2013 Annual Report contains forward-looking statements. Forward-looking statements include, among other things, statements concerning retail sales, retail rates, the strategic goals for the wholesale business, customer growth, economic recovery, fuel and environmental cost recovery and other rate actions, current and proposed environmental regulations and related estimated expenditures, access to sources of capital, projections for the qualified pension plan, postretirement benefit plan, and nuclear decommissioning trust fund contributions, financing activities, completion dates of construction projects, plans and estimated costs for new generation resources, filings with state and federal regulatory authorities, impact of the ATRA, estimated sales and purchases under new power sale and purchase agreements, and estimated construction and other 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 including regulation of water, coal combustion residuals, and emissions of sulfur, nitrogen, carbon, soot, particulate matter, hazardous air pollutants, including mercury, and other substances, 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 the pending EPA civil actions against certain Southern Company subsidiaries, FERC matters, and Internal Revenue Service 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 recent recession, population and business growth (and declines), the effects of energy conservation 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;
- ability to control costs and avoid cost overruns during the development and construction of facilities, which include the development and construction of facilities with designs that have not been finalized or previously constructed, including changes in labor costs and productivity factors, adverse weather conditions, shortages and inconsistent quality of equipment, materials, and labor, contractor or supplier delay or non-performance under construction or other agreements, delays associated with start-up activities, including major equipment failure, system integration, and operations, and/or unforeseen engineering problems;
- ability to construct facilities in accordance with the requirements of permits and licenses and to satisfy any operational and environmental performance standards, including the requirements of tax credits and other incentives;
- 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;
- regulatory approvals and actions related to Plant Vogtle Units 3 and 4, including Georgia PSC approvals and NRC actions;

- actions related to cost recovery for the Kemper IGCC, including actions relating to proposed securitization, Mississippi PSC approval of Mississippi Power's proposed rate recovery plan, as ultimately amended, which includes the ability to complete the proposed sale of an interest in the Kemper IGCC to SMEPA, the ability to utilize bonus depreciation, which currently requires that the Kemper IGCC be placed in service in 2014, and satisfaction of requirements to utilize investment tax credits and grants;
- Mississippi PSC review of the prudence of Kemper IGCC costs;
- the outcome of any legal or regulatory proceedings regarding the Mississippi PSC's issuance of the CPCN for the Kemper IGCC, the settlement agreement between Mississippi Power and the Mississippi PSC, or the 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;

- the inherent risks involved in operating and constructing nuclear generating facilities, including environmental, health, regulatory, natural disaster, terrorism, or 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 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 terrorist incidents and the threat of terrorist incidents, including cyber intrusion;
- interest rate fluctuations and financial market conditions and the results of financing efforts, including Southern Company's and its subsidiaries' credit ratings;
- the impacts of any potential U.S. credit rating downgrade or other 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 and its subsidiaries to obtain additional generating capacity at competitive prices;
- catastrophic events such as fires, earthquakes, explosions, floods, hurricanes, 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, 2013, 2012, and 2011
Southern Company and Subsidiary Companies 2013 Annual Report

	2013	2012	2011
		(in millions)	
Operating Revenues:			
Retail revenues	$14,541	$14,187	$15,071
Wholesale revenues	1,855	1,675	1,905
Other electric revenues	639	616	611
Other revenues	52	59	70
Total operating revenues	17,087	16,537	17,657
Operating Expenses:			
Fuel	5,510	5,057	6,262
Purchased power	461	544	608
Other operations and maintenance	3,846	3,772	3,938
Depreciation and amortization	1,901	1,787	1,717
Taxes other than income taxes	934	914	901
Estimated loss on Kemper IGCC	1,180	—	—
Total operating expenses	13,832	12,074	13,426
Operating Income	3,255	4,463	4,231
Other Income and (Expense):			
Allowance for equity funds used during construction	190	143	153
Interest income	19	40	21
Interest expense, net of amounts capitalized	(824)	(859)	(857)
Other income (expense), net	(81)	(38)	(61)
Total other income and (expense)	(696)	(714)	(744)
Earnings Before Income Taxes	2,559	3,749	3,487
Income taxes	849	1,334	1,219
Consolidated Net Income	1,710	2,415	2,268
Dividends on Preferred and Preference Stock of Subsidiaries	66	65	65
Consolidated Net Income After Dividends on Preferred and Preference Stock of Subsidiaries	$1,644	$2,350	$2,203
Common Stock Data:			
Earnings per share (EPS)—			
Basic EPS	$1.88	$2.70	$2.57
Diluted EPS	1.87	2.67	2.55
Average number of shares of common stock outstanding — (in millions)			
Basic	877	871	857
Diluted	881	879	864

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

Table of Contents Index to Financial Statements

CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME
For the Years Ended December 31, 2013, 2012, and 2011
Southern Company and Subsidiary Companies 2013 Annual Report

	2013	2012	2011
		(in millions)	
Consolidated Net Income	$1,710	$2,415	$2,268
Other comprehensive income:			
Qualifying hedges:			
Changes in fair value, net of tax of $-, $(7), and $(10), respectively	—	(12)	(18)
Reclassification adjustment for amounts included in net income, net of tax of $5, $7, and $6, respectively	9	11	9
Marketable securities:			
Change in fair value, net of tax of $(2), $-, and $(2), respectively	(3)	—	(4)
Pension and other postretirement benefit plans:			
Benefit plan net gain (loss), net of tax of $22, $(2), and $(1), respectively	36	(3)	(2)
Reclassification adjustment for amounts included in net income, net of tax of $4, $(4), and $(14), respectively	6	(8)	(26)
Total other comprehensive income (loss)	48	(12)	(41)
Dividends on preferred and preference stock of subsidiaries	(66)	(65)	(65)
Consolidated Comprehensive Income	$1,692	$2,338	$2,162

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

CONSOLIDATED STATEMENTS OF CASH FLOWS
For the Years Ended December 31, 2013, 2012, and 2011
Southern Company and Subsidiary Companies 2013 Annual Report

	2013	2012 (in millions)	2011
Operating Activities:			
Consolidated net income	$1,710	$2,415	$2,268
Adjustments to reconcile consolidated net income to net cash provided from operating activities —			
Depreciation and amortization, total	2,298	2,145	2,048
Deferred income taxes	496	1,096	1,155
Investment tax credits	302	128	85
Allowance for equity funds used during construction	(190)	(143)	(153)
Pension, postretirement, and other employee benefits	131	(398)	(45)
Stock based compensation expense	59	55	42
Estimated loss on Kemper IGCC	1,180	—	—
Retail fuel cost over recovery - long-term	(123)	123	—
Other, net	82	(72)	(70)
Changes in certain current assets and liabilities —			
-Receivables	(153)	234	362
-Fossil fuel stock	481	(452)	(62)
-Materials and supplies	36	(97)	(60)
-Other current assets	(11)	(37)	(17)
-Accounts payable	72	(89)	(5)
-Accrued taxes	(85)	(71)	330
-Accrued compensation	(138)	(28)	10
-Retail fuel cost over recovery - short-term	(66)	129	(3)
-Other current liabilities	16	(40)	18
Net cash provided from operating activities	6,097	4,898	5,903
Investing Activities:			
Property additions	(5,463)	(4,809)	(4,525)
Investment in restricted cash	(149)	(280)	1
Distribution of restricted cash	96	284	63
Nuclear decommissioning trust fund purchases	(986)	(1,046)	(2,195)
Nuclear decommissioning trust fund sales	984	1,043	2,190
Cost of removal, net of salvage	(131)	(149)	(93)
Change in construction payables, net	(126)	(84)	198
Other investing activities	33	(127)	178
Net cash used for investing activities	(5,742)	(5,168)	(4,183)
Financing Activities:			
Increase (decrease) in notes payable, net	662	(30)	(438)
Proceeds —			
Long-term debt issuances	2,938	4,404	3,719
Interest-bearing refundable deposit related to asset sale	—	150	—
Preference stock	50	—	—
Common stock issuances	695	397	723
Redemptions and repurchases —			
Long-term debt	(2,830)	(3,169)	(3,170)

Common stock repurchased	(20)	(430)	—
Payment of common stock dividends	(1,762)	(1,693)	(1,601)
Payment of dividends on preferred and preference stock of subsidiaries	(66)	(65)	(65)
Other financing activities	9	19	(20)
Net cash used for financing activities	(324)	(417)	(852)
Net Change in Cash and Cash Equivalents	31	(687)	868
Cash and Cash Equivalents at Beginning of Year	628	1,315	447
Cash and Cash Equivalents at End of Year	$659	$628	$1,315

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

Table of Contents Index to Financial Statements

CONSOLIDATED BALANCE SHEETS
At December 31, 2013 and 2012
Southern Company and Subsidiary Companies 2013 Annual Report

Assets	2013	2012
		(in millions)
Current Assets:		
Cash and cash equivalents	$659	$628
Restricted cash and cash equivalents	—	7
Receivables —		
Customer accounts receivable	1,027	961
Unbilled revenues	448	441
Under recovered regulatory clause revenues	58	29
Other accounts and notes receivable	304	235
Accumulated provision for uncollectible accounts	(18)	(17)
Fossil fuel stock, at average cost	1,339	1,819
Materials and supplies, at average cost	959	1,000
Vacation pay	171	165
Prepaid expenses	489	657
Other regulatory assets, current	124	163
Other current assets	39	74
Total current assets	5,599	6,162
Property, Plant, and Equipment:		
In service	66,021	63,251
Less accumulated depreciation	23,059	21,964
Plant in service, net of depreciation	42,962	41,287
Other utility plant, net	240	263
Nuclear fuel, at amortized cost	855	851
Construction work in progress	7,151	5,989
Total property, plant, and equipment	51,208	48,390
Other Property and Investments:		
Nuclear decommissioning trusts, at fair value	1,465	1,303
Leveraged leases	665	670
Miscellaneous property and investments	218	216
Total other property and investments	2,348	2,189
Deferred Charges and Other Assets:		
Deferred charges related to income taxes	1,432	1,385
Prepaid pension costs	419	—
Unamortized debt issuance expense	139	133
Unamortized loss on reacquired debt	293	309
Other regulatory assets, deferred	2,557	4,032
Other deferred charges and assets	551	549
Total deferred charges and other assets	5,391	6,408
Total Assets	$64,546	$63,149

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

CONSOLIDATED BALANCE SHEETS
At December 31, 2013 and 2012
Southern Company and Subsidiary Companies 2013 Annual Report

Liabilities and Stockholders' Equity	2013	2012
		(in millions)
Current Liabilities:		
Securities due within one year	$469	$2,335
Interest-bearing refundable deposit related to asset sale	150	150
Notes payable	1,482	825
Accounts payable	1,376	1,387
Customer deposits	380	370
Accrued taxes —		
Accrued income taxes	13	10
Other accrued taxes	456	391
Accrued interest	251	237
Accrued vacation pay	217	212
Accrued compensation	303	433
Other regulatory liabilities, current	92	107
Other current liabilities	347	557
Total current liabilities	5,536	7,014
Long-Term Debt (See accompanying statements)	21,344	19,274
Deferred Credits and Other Liabilities:		
Accumulated deferred income taxes	10,563	9,938
Deferred credits related to income taxes	202	211
Accumulated deferred investment tax credits	966	894
Employee benefit obligations	1,461	2,540
Asset retirement obligations	2,006	1,748
Other cost of removal obligations	1,270	1,194
Other regulatory liabilities, deferred	475	289
Other deferred credits and liabilities	584	668
Total deferred credits and other liabilities	17,527	17,482
Total Liabilities	44,407	43,770
Redeemable Preferred Stock of Subsidiaries (See accompanying statements)	375	375
Total Stockholders' Equity (See accompanying statements)	19,764	19,004
Total Liabilities and Stockholders' Equity	$64,546	$63,149
Commitments and Contingent Matters (See notes)		

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

Table of Contents Index to Financial Statements

CONSOLIDATED STATEMENTS OF CAPITALIZATION
At December 31, 2013 and 2012
Southern Company and Subsidiary Companies 2013 Annual Report

		2013	2012	2013	2012
		(in millions)		(percent of total)	
Long-Term Debt:					
Long-term debt payable to affiliated trusts —					
Maturity					
Variable rate (3.35% at 1/1/14) due 2042		$206	$206		
Total long-term debt payable to affiliated trusts		206	206		
Long-term senior notes and debt —					
Maturity	Interest Rates				
2013	1.30% to 6.00%	—	1,436		
2014	3.25% to 4.90%	428	434		
2015	0.55% to 5.25%	2,375	2,375		
2016	1.95% to 5.30%	1,360	1,360		
2017	5.50% to 5.90%	1,095	1,095		
2018	2.20% to 5.40%	850	250		
2019 through 2051	1.63% to 8.20%	10,798	9,823		
Variable rates (0.58% to 1.21% at 1/1/13) due 2013		—	876		
Variable rate (1.29% at 1/1/14) due 2014		11	—		
Variable rates (0.77% to 0.97% at 1/1/14) due 2015		525	—		
Variable rates (0.57% to 0.65% at 1/1/14) due 2016		450	—		
Total long-term senior notes and debt		17,892	17,649		
Other long-term debt —					
Pollution control revenue bonds —					
Maturity	Interest Rates				
2019 through 2049	0.40% to 6.00%	1,478	1,593		
Variable rate (0.04% at 1/1/14) due 2015		54	54		
Variable rate (0.06% at 1/1/14) due 2016		4	4		
Variable rate (0.09% to 0.10% at 1/1/14) due 2017		36	36		
Variable rate (0.04% at 1/1/14) due 2018		19	19		
Variable rates (0.02% to 0.13% at 1/1/14) due 2020 to 2052		1,642	1,645		
Plant Daniel revenue bonds (7.13%) due 2021		270	270		
Total other long-term debt		3,503	3,621		
Capitalized lease obligations		163	80		
Unamortized debt premium (related to plant acquisition)		79	88		
Unamortized debt discount		(30)	(35)		
Total long-term debt (annual interest requirement — $805 million)		21,813	21,609		
Less amount due within one year		469	2,335		
Long-term debt excluding amount due within one year		21,344	19,274	51.5 %	49.9 %

Table of Contents Index to Financial Statements

CONSOLIDATED STATEMENTS OF CAPITALIZATION (continued)
At December 31, 2013 and 2012
Southern Company and Subsidiary Companies 2013 Annual Report

	2013	2012	2013	2012
	(in millions)		(percent of total)	
Redeemable Preferred Stock of Subsidiaries:				
Cumulative preferred stock				
$100 par or stated value — 4.20% to 5.44%				
Authorized — 20 million shares				
Outstanding — 1 million shares	81	81		
$1 par value — 5.20% to 5.83%				
Authorized — 28 million shares				
Outstanding — 12 million shares: $25 stated value	294	294		
Total redeemable preferred stock of subsidiaries (annual dividend requirement — $20 million)	375	375	0.9	1.0
Common Stockholders' Equity:				
Common stock, par value $5 per share —	4,461	4,389		
Authorized — 1.5 billion shares				
Issued — 2013: 893 million shares				
— 2012: 878 million shares				
Treasury — 2013: 5.7 million shares				
— 2012: 10.0 million shares				
Paid-in capital	5,362	4,855		
Treasury, at cost	(250)	(450)		
Retained earnings	9,510	9,626		
Accumulated other comprehensive income (loss)	(75)	(123)		
Total common stockholders' equity	19,008	18,297	45.8	47.3
Preferred and Preference Stock of Subsidiaries:				
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	343	343		
— 5.63% to 6.50% — 14 million shares (non-cumulative)				
Outstanding — $100 par or stated value	368	319		
— 5.60% to 6.50% — 2013: 4 million shares (non-cumulative)				
— 2012: 3 million shares (non-cumulative)				
Total preferred and preference stock of subsidiaries (annual dividend requirement — $48 million)	756	707	1.8	1.8
Total stockholders' equity	19,764	19,004		
Total Capitalization	$41,483	$38,653	100.0 %	100.0 %

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

Table of Contents Index to Financial Statements

CONSOLIDATED STATEMENTS OF STOCKHOLDERS' EQUITY
For the Years Ended December 31, 2013, 2012, and 2011
Southern Company and Subsidiary Companies 2013 Annual Report

	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	Total
	(in thousands)		(in millions)						
Balance at December 31, 2010	843,814	(474)	$4,219	$3,702	$(15)	$8,366	$(70)	$707	$16,909
Net income after dividends on preferred and preference stock of subsidiaries	—	—	—	—	—	2,203	—	—	2,203
Other comprehensive income (loss)	—	—	—	—	—	—	(41)	—	(41)
Stock issued	21,850	—	109	616	—	—	—	—	725
Stock-based compensation	—	—	—	89	—	—	—	—	89
Cash dividends	—	—	—	—	—	(1,601)	—	—	(1,601)
Other	—	(65)	—	3	(2)	—	—	—	1
Balance at December 31, 2011	865,664	(539)	4,328	4,410	(17)	8,968	(111)	707	18,285
Net income after dividends on preferred and preference stock of subsidiaries	—	—	—	—	—	2,350	—	—	2,350
Other comprehensive income (loss)	—	—	—	—	—	—	(12)	—	(12)
Stock issued	12,139	—	61	336	—	—	—	—	397
Stock repurchased, at cost	—	(9,440)	—	—	(430)	—	—	—	(430)
Stock-based compensation	—	—	—	106	—	—	—	—	106
Cash dividends	—	—	—	—	—	(1,693)	—	—	(1,693)
Other	—	(56)	—	3	(3)	1	—	—	1
Balance at December 31, 2012	877,803	(10,035)	4,389	4,855	(450)	9,626	(123)	707	19,004
Net income after dividends on preferred and preference stock of subsidiaries	—	—	—	—	—	1,644	—	—	1,644
	—	—	—	—	—	—	48	—	48

Other comprehensive income (loss)									
Stock issued	14,930	4,443	72	441	203	—	—	49	765
Stock-based compensation	—	—	—	65	—	—	—	—	65
Cash dividends	—	—	—	—	—	(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

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

NOTES TO FINANCIAL STATEMENTS
Southern Company and Subsidiary Companies 2013 Annual Report

Index to the Notes to Financial Statements

NOTES (continued)
Southern Company and Subsidiary Companies 2013 Annual Report

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 Company (Southern Power), Southern Company Services, Inc. (SCS), Southern Communications Services, Inc. (SouthernLINC Wireless), Southern Company Holdings, Inc. (Southern Holdings), Southern Nuclear Operating Company, Inc. (Southern Nuclear), and other direct and indirect subsidiaries. The traditional operating companies – Alabama Power Company (Alabama Power), Georgia Power Company (Georgia Power), Gulf Power Company (Gulf Power), and Mississippi Power Company (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. 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 (VIEs) where the Company has an equity investment, but is not the primary beneficiary. All material intercompany transactions have been eliminated in consolidation. Certain prior years' data presented in the financial statements have been reclassified to conform to the current year presentation.

The traditional operating companies, Southern Power, and certain of their subsidiaries are subject to regulation by the Federal Energy Regulatory Commission (FERC), and the traditional operating companies are also subject to regulation by their respective state public service commissions (PSC). The companies follow generally accepted accounting principles (GAAP) in the U.S. 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.

Regulatory Assets and Liabilities

The traditional operating companies are subject to the provisions of the Financial Accounting Standards Board 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.

Table of Contents Index to Financial Statements

NOTES (continued)
Southern Company and Subsidiary Companies 2013 Annual Report

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

	2013	2012	Note
	(in millions)		
Deferred income tax charges	$1,376	$1,318	(a)
Deferred income tax charges — Medicare subsidy	65	72	(j)
Asset retirement obligations-asset	145	141	(a,h)
Asset retirement obligations-liability	(139)	(71)	(a,h)
Other cost of removal obligations	(1,289)	(1,225)	(a)
Deferred income tax credits	(203)	(212)	(a)
Loss on reacquired debt	293	309	(b)
Vacation pay	171	165	(c,h)
Under recovered regulatory clause revenues	70	38	(d)
Property damage reserves	(191)	(193)	(g)
Cancelled construction projects	70	65	(m)
Power purchase agreement charges	180	138	(h,n)
Fuel-hedging-asset	58	118	(h,o)
Other regulatory assets	337	276	(f)
Environmental remediation-asset	62	74	(g,h)
Other regulatory liabilities	(126)	(100)	(b,l,i)
Kemper IGCC* regulatory assets	76	36	(k)
Kemper regulatory deferral	(91)	—	(k)
Retiree benefit plans	1,760	3,373	(e,h)
Total regulatory assets (liabilities), net	$2,624	$4,322	

* Integrated coal gasification combined cycle electric generating plant located in Kemper County, Mississippi (Kemper IGCC).

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

(a) Asset retirement and removal assets and liabilities are recorded, deferred income tax assets are recovered, and deferred income tax liabilities are amortized over the related property lives, which may range up to 70 years. Asset retirement and removal assets and liabilities will be settled and trued up following completion of the related activities. At December 31, 2013, other cost of removal obligations included $43 million that will be amortized over the three-year period from January 2014 through December 2016 in accordance with Georgia Power's Alternate Rate Plan for the years 2014 through 2016 (2013 ARP). See Note 3 under "Retail Regulatory Matters" for additional information.

(b) 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.

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

(d) Recorded and recovered or amortized as approved or accepted by the appropriate state PSCs over periods generally not exceeding 10 years.

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

(f) Comprised of numerous immaterial components including storm damage reserves, nuclear and generating plant outage costs, property taxes, post-retirement benefits, generation site selection/evaluation costs, power purchase agreement (PPA) capacity, demand side management cost deferrals, regulatory deferrals, building leases, net book value of retired generating units, Plant Daniel Units 3 and 4 regulatory assets, and other miscellaneous assets. These costs are recorded and recovered or amortized as approved by the appropriate state PSC over periods generally not exceeding, as applicable, 10 years or over the remaining life of the asset but not beyond 2031.

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

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

(i) Recovered and amortized as approved or accepted by the appropriate state PSC over the life of the contract.

(j) Recovered and amortized as approved by the appropriate state PSCs over periods not exceeding 15 years.

(k) For additional information, See Note 3 under "Integrated Coal Gasification Combined Cycle."

(l) Comprised of immaterial components including over recovered regulatory clause revenues, state income tax credits, fuel-hedging liabilities, mine reclamation and remediation liabilities, PPA credits, and other liabilities that are recorded and recovered or amortized as approved by the appropriate state PSCs generally over periods not exceeding 10 years, except for PPA credits that are recovered over the life of the PPA for periods up to 14 years.

(m) Costs associated with construction of environmental controls that will not be completed as a result of unit retirements and amortized over nine years in accordance with the 2013 ARP.

(n) Recovered over the life of the PPA for periods up to 14 years.

(o) 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.

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 other comprehensive income (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," and "Integrated Coal Gasification Combined Cycle" for additional information.

Revenues

Wholesale capacity revenues are generally recognized on a levelized basis over the appropriate contract period. Energy and other revenues are recognized as services are provided. Unbilled revenues related to retail sales are accrued at the end of each fiscal period. Electric rates for the 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. See Note 3 under "Nuclear Fuel Disposal Costs" for additional information.

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 investment tax credits (ITCs) for the traditional operating companies are amortized over the lives 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 $16 million in 2013, $23 million in 2012, and $19 million in 2011. At December 31, 2013, all ITCs available to reduce federal income taxes payable had not been utilized. The remaining ITCs will be carried forward and utilized in future years. Additionally, several subsidiaries have state ITCs, which are recognized in the period in which the credit is claimed on the state income tax return. A portion of the state ITCs available to reduce state income taxes payable was not utilized currently and will be carried forward and utilized in future years.

Under the American Recovery and Reinvestment Act of 2009, certain projects at Southern Power are eligible for 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. Credits amortized in this manner amounted to $5.5 million and $2.6 million in 2013 and 2012, respectively. 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 as costs are incurred during the construction period.

In accordance with accounting standards related to the uncertainty in income taxes, 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.

Table of Contents Index to Financial Statements

NOTES (continued)
Southern Company and Subsidiary Companies 2013 Annual Report

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

	2013	2012
	(in millions)	
Generation	$35,360	$33,444
Transmission	9,289	8,747
Distribution	16,499	15,958
General	3,958	4,208
Plant acquisition adjustment	123	124
Utility plant in service	65,229	62,481
Information technology equipment and software	242	230
Communications equipment	437	430
Other	113	110
Other plant in service	792	770
Total plant in service	$66,021	$63,251

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 and Georgia Power range from 18 to 24 months for each unit. In accordance with a Georgia PSC order, Georgia Power deferred the costs of certain significant inspection costs for the combustion turbine units at Plant McIntosh and amortized such costs over 10 years, which approximated the expected maintenance cycle of the units. All inspection costs were fully amortized in 2013.

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,	
	2013	2012
	(in millions)	
Office building	$61	$61
Nitrogen plant	83	—
Computer-related equipment	62	58
Gas pipeline	6	—
Less: Accumulated amortization	(48)	(39)
Balance, net of amortization	$164	$80

The amount of non-cash property additions recognized for the years ended December 31, 2013, 2012, and 2011 was $411 million, $524 million, and $929 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, 2013, 2012, and 2011 were $107 million, $14 million, and $21 million, respectively.

Acquisitions

Southern Power acquires generation assets as part of its overall growth strategy. Southern Power accounts for business acquisitions from non-affiliates as business combinations. Accordingly, Southern Power has included these operations in the consolidated financial statements from the respective date of acquisition. The purchase price, including contingent consideration, if any, of each acquisition was allocated based on the fair value of the identifiable assets and liabilities. Assets acquired that do not meet the definition of a business in accordance with GAAP are accounted for as asset acquisitions. The purchase price of each asset acquisition was allocated based on the relative fair value of assets acquired. Any due diligence or transition costs incurred by Southern Power for successful or potential acquisitions have been expensed as incurred.

NOTES (continued)
Southern Company and Subsidiary Companies 2013 Annual Report

Acquisitions entered into or made by Southern Power and Turner Renewable Energy through Southern Turner Renewable Energy, LLC during 2013 and 2012 are detailed in the table below:

	MW Capacity*	Year of Operation	Party Under PPA Contract for Plant Output	PPA Contract Period	Purchase Price
					(millions)
Adobe Solar, LLC [(a)]	20	2014	Southern California Edison Company	20 years	$100.0
Campo Verde Solar, LLC [(b)]	139	2013	San Diego Gas & Electric Company	20 years	$136.6
Spectrum Nevada Solar, LLC [(c)]	30	2013	Nevada Power Company	25 years	$17.6
Apex Nevada Solar, LLC	20	2012	Nevada Power Company	25 years	$102.0

* megawatt (MW)
(a) This acquisition is expected to occur in spring 2014, and the purchase price is expected to be $100 million.
(b) Under an engineering, procurement, and construction agreement, an additional $355.5 million was paid to a subsidiary of First Solar Inc. to complete the construction of the solar facility.
(c) Under an engineering, procurement, and construction agreement, an additional $104 million was paid to a subsidiary of Sun Edison, LLC to complete the construction of the solar facility.

Depreciation and Amortization

Depreciation of the original cost of utility plant in service is provided primarily by using composite straight-line rates, which approximated 3.3% in 2013, 3.2% in 2012, and 3.2% in 2011. 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 $22.5 billion and $21.5 billion at December 31, 2013 and 2012, 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.

In 2009, the Georgia PSC approved an accounting order allowing Georgia Power to amortize a portion of its regulatory liability related to other cost of removal obligations. Under the terms of Georgia Power's Alternate Rate Plan for the years 2011 through 2013 (2010 ARP), Georgia Power amortized approximately $31 million annually of the remaining regulatory liability related to other cost of removal obligations over the three years ended December 31, 2013. Under the terms of the 2013 ARP, an additional $43 million will be amortized ratably over the three years ending December 31, 2016. See Note 3 under "Retail Regulatory Matters – Georgia Power – Rate Plans" for additional information.

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 $513 million and $479 million at December 31, 2013 and 2012, respectively.

Asset Retirement Obligations and Other Costs of Removal

Asset retirement obligations (ARO) are computed as the present value of the 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. 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 asset retirement obligations primarily relates to the decommissioning of the Southern Company system's nuclear facilities, Plants Farley, Hatch, and Vogtle. In addition, the Southern Company system has retirement obligations related to various landfill sites, ash ponds, 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

asset retirement obligations will be recognized when sufficient information becomes available to support a reasonable estimation of the asset retirement obligation. 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 asset retirement obligations included in the balance sheets are as follows:

	2013	2012
	(in millions)	
Balance at beginning of year	$1,757	$1,344
Liabilities incurred	6	45
Liabilities settled	(16)	(16)
Accretion	97	112
Cash flow revisions	174	272
Balance at end of year	$2,018	$1,757

The increase in cash flow revisions in 2013 related to revisions to the nuclear decommissioning ARO based on Alabama Power's updated decommissioning study and Georgia Power's updated estimates for ash ponds in connection with the retirement of certain coal-fired generating units. The increase in cash flow revisions in 2012 related to updated estimates for some of the Southern Company system's ash ponds in connection with the retirement of certain coal-fired units and revisions to the nuclear decommissioning ARO based on Georgia Power's updated decommissioning study.

Nuclear Decommissioning

The U.S. Nuclear Regulatory Commission (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 Internal Revenue Service (IRS). The Funds are required to be held by one or more trustees with an individual net worth of at least $100 million. The FERC requires the Funds' managers to exercise the standard of care in investing that a "prudent investor" would use in the same circumstances. The FERC regulations also require that the Funds' managers may not invest in any securities of the utility for which it manages funds or its affiliates, except for investments tied to market indices or other mutual funds. While Southern Company is 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 asset retirement obligations 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 so loaned are fully collateralized by cash, letters of credit, and securities issued or guaranteed by the U.S. government, its agencies, and the instrumentalities. As of December 31, 2013 and 2012, approximately $32 million and $91 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 $33 million and $93 million at December 31, 2013 and 2012, 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, 2013, investment securities in the Funds totaled $1.5 billion, consisting of equity securities of $896 million, debt securities of $528 million, and $40 million of other securities. At December 31, 2012, investment securities in the Funds totaled $1.3 billion, consisting of equity securities of $718 million, debt securities of $564 million, and $20 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 $1.0 billion, $1.0 billion, and $2.2 billion in 2013, 2012, and 2011, respectively, all of which were reinvested. For 2013, fair value increases, including reinvested interest and dividends and excluding the Funds' expenses, were $181 million, of which $5 million related to realized gains and $119 million related to unrealized gains related to securities held in the Funds at December 31, 2013. For 2012, fair value increases, including reinvested interest and dividends and excluding the Funds' expenses, were $137 million, of which $4 million related to realized gains and $75 million related to unrealized gains related to securities held in the Funds at December 31, 2012. For 2011, fair value increases, including reinvested interest and dividends and excluding the Funds' expenses, were $29 million, of which $41 million related to realized gains and $60 million related to unrealized losses related to securities held in the Funds at December 31, 2011. 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 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, 2013 and 2012, the accumulated provisions for decommissioning were as follows:

	External Trust Funds		Internal Reserves		Total	
	2013	2012	2013	2012	2013	2012
	(in millions)					
Plant Farley	$713	$604	$21	$22	$734	$626
Plant Hatch	469	435	—	—	469	435
Plant Vogtle Units 1 and 2	277	256	—	—	277	256

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, 2013 based on the most current studies, which were performed in 2013 for Alabama Power's Plant Farley and in 2012 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	2068	2072
	(in millions)		
Site study costs:			
Radiated structures	$1,362	$680	$568
Non-radiated structures	80	51	76
Total site study costs	$1,442	$731	$644

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. The Georgia PSC approved annual decommissioning cost for ratemaking of $2 million for Plant Hatch for 2011 through 2013. Under the 2013 ARP, the annual decommissioning cost through 2016 for ratemaking is $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 allowance for funds used during construction (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 15.0%, 8.2%, and 9.1% of net income for 2013, 2012, and 2011, respectively.

Cash payments for interest totaled $759 million, $803 million, and $832 million in 2013, 2012, and 2011, respectively, net of amounts capitalized of $92 million, $83 million, and $78 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 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 $28 million in 2013 and 2012. 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 2013 and 2012, there were no such additional accruals. See Note 3 under "Retail Regulatory Matters – Alabama Power – Natural Disaster Reserve" for additional information regarding Alabama Power's natural disaster reserve.

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.

NOTES (continued)
Southern Company and Subsidiary Companies 2013 Annual Report

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

	2013	2012
	(in millions)	
Net rentals receivable	$1,440	$1,214
Unearned income	(775)	(544)
Investment in leveraged leases	665	670
Deferred taxes from leveraged leases	(287)	(278)
Net investment in leveraged leases	$378	$392

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

	2013	2012	2011
	(in millions)		
Pretax leveraged lease income (loss)	$(5)	$21	$25
Income tax expense	2	(8)	(9)
Net leveraged lease income (loss)	$(3)	$13	$16

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 U.S. Environmental Protection Agency (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 (included in "Other" or shown separately as "Risk Management Activities") and are measured at fair value. See Note 10 for additional information. 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. Other derivative contracts qualify as cash flow hedges of anticipated transactions or are recoverable through the traditional operating companies' fuel-hedging programs. This results 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 are marked to market through current period income and are recorded on a net basis in the statements of income. See Note 11 for additional information.
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, 2013, 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.

Table of Contents Index to Financial Statements

NOTES (continued)
Southern Company and Subsidiary Companies 2013 Annual Report

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, 2012	$(45)	$3	$(81)	$(123)
Current period change	9	(3)	42	48
Balance at December 31, 2013	$(36)	$—	$(39)	$(75)

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 were made to the qualified pension plan during 2013. No mandatory contributions to the qualified pension plan are anticipated for the year ending December 31, 2014. 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, 2014, other postretirement trust contributions are expected to total approximately $13 million.

Actuarial Assumptions

The weighted average rates assumed in the actuarial calculations used to determine both the benefit obligations as of the measurement date and the net periodic costs for the pension and other postretirement benefit plans for the following year are presented below. Net periodic benefit costs were calculated in 2010 for the 2011 plan year using discount rates for the pension plans and the other postretirement benefit plans of 5.52% and 5.40%, respectively, and an annual salary increase of 3.84%.

	2013	2012	2011
Discount rate:			
Pension plans	5.02%	4.26%	4.98%
Other postretirement benefit plans	4.85	4.05	4.88
Annual salary increase	3.59	3.59	3.84
Long-term return on plan assets:			
Pension plans	8.20	8.20	8.45
Other postretirement benefit plans	7.13	7.29	7.39

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.

NOTES (continued)
Southern Company and Subsidiary Companies 2013 Annual Report

An additional assumption used in measuring the accumulated other postretirement benefit obligations (APBO) was a weighted average medical care cost trend rate of 7.00% for 2014, decreasing gradually to 5.00% through the year 2021 and remaining at that level thereafter. 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, 2013 as follows:

	1 Percent Increase	1 Percent Decrease
	(in millions)	
Benefit obligation	$103	$(88)
Service and interest costs	5	(4)

Pension Plans

The total accumulated benefit obligation for the pension plans was $8.1 billion at December 31, 2013 and $8.5 billion at December 31, 2012. Changes in the projected benefit obligations and the fair value of plan assets during the plan years ended December 31, 2013 and 2012 were as follows:

	2013	2012
	(in millions)	
Change in benefit obligation		
Benefit obligation at beginning of year	$9,302	$8,079
Service cost	232	198
Interest cost	389	393
Benefits paid	(357)	(336)
Actuarial (gain) loss	(703)	968
Balance at end of year	8,863	9,302
Change in plan assets		
Fair value of plan assets at beginning of year	7,953	6,800
Actual return on plan assets	1,098	1,010
Employer contributions	39	479
Benefits paid	(357)	(336)
Fair value of plan assets at end of year	8,733	7,953
Accrued liability	$(130)	$(1,349)

At December 31, 2013, the projected benefit obligations for the qualified and non-qualified pension plans were $8.3 billion and $549 million, respectively. All pension plan assets are related to the qualified pension plan.

Amounts recognized in the balance sheets at December 31, 2013 and 2012 related to the Company's pension plans consist of the following:

	2013	2012
	(in millions)	
Prepaid pension costs	$419	$—
Other regulatory assets, deferred	1,651	3,013
Other current liabilities	(40)	(37)
Employee benefit obligations	(509)	(1,312)
Accumulated OCI	64	125

NOTES (continued)
Southern Company and Subsidiary Companies 2013 Annual Report

Presented below are the amounts included in accumulated OCI and regulatory assets at December 31, 2013 and 2012 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 2014.

	Prior Service Cost (in millions)	Net (Gain) Loss
Balance at December 31, 2013:		
Accumulated OCI	$5	$59
Regulatory assets	75	1,575
Total	$80	$1,634
Balance at December 31, 2012:		
Accumulated OCI	$7	$118
Regulatory assets	100	2,913
Total	$107	$3,031
Estimated amortization in net periodic pension cost in 2014:		
Accumulated OCI	$1	$4
Regulatory assets	25	106
Total	$26	$110

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, 2013 and 2012 are presented in the following table:

	Accumulated OCI (in millions)	Regulatory Assets
Balance at December 31, 2011	$109	$2,614
Net loss	21	519
Reclassification adjustments:		
Amortization of prior service costs	(1)	(29)
Amortization of net gain (loss)	(4)	(91)
Total reclassification adjustments	(5)	(120)
Total change	16	399
Balance at December 31, 2012	$125	$3,013
Net gain	(52)	(1,145)
Change in prior service costs	—	1
Reclassification adjustments:		
Amortization of prior service costs	(1)	(26)
Amortization of net gain (loss)	(8)	(192)
Total reclassification adjustments	(9)	(218)
Total change	(61)	(1,362)
Balance at December 31, 2013	$64	$1,651

NOTES (continued)
Southern Company and Subsidiary Companies 2013 Annual Report

Components of net periodic pension cost were as follows:

	2013	2012	2011
	(in millions)		
Service cost	$232	$198	$184
Interest cost	389	393	389
Expected return on plan assets	(603)	(581)	(607)
Recognized net loss	200	95	21
Net amortization	27	30	32
Net periodic pension cost	$245	$135	$19

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, 2013, estimated benefit payments were as follows:

	Benefit Payments
	(in millions)
2014	$399
2015	422
2016	446
2017	471
2018	492
2019 to 2023	2,795

Other Postretirement Benefits

Changes in the APBO and in the fair value of plan assets during the plan years ended December 31, 2013 and 2012 were as follows:

	2013	2012
	(in millions)	
Change in benefit obligation		
Benefit obligation at beginning of year	$1,872	$1,787
Service cost	24	21
Interest cost	74	85
Benefits paid	(94)	(99)
Actuarial (gain) loss	(200)	71
Retiree drug subsidy	6	7
Balance at end of year	1,682	1,872
Change in plan assets		
Fair value of plan assets at beginning of year	821	765
Actual return on plan assets	129	93
Employer contributions	39	55
Benefits paid	(88)	(92)
Fair value of plan assets at end of year	901	821
Accrued liability	$(781)	$(1,051)

II-67

Table of Contents Index to Financial Statements

NOTES (continued)
Southern Company and Subsidiary Companies 2013 Annual Report

Amounts recognized in the balance sheets at December 31, 2013 and 2012 related to the Company's other postretirement benefit plans consist of the following:

	2013	2012
	(in millions)	
Other regulatory assets, deferred	$109	$360
Other current liabilities	(4)	(3)
Employee benefit obligations	(777)	(1,048)
Other regulatory liabilities, deferred	(36)	—
Accumulated OCI	1	7

Presented below are the amounts included in accumulated OCI and net regulatory assets (liabilities) at December 31, 2013 and 2012 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 2014.

	Prior Service Cost	Net (Gain) Loss	Transition Obligation
		(in millions)	
Balance at December 31, 2013:			
Accumulated OCI	$—	$1	$—
Net regulatory assets (liabilities)	9	64	—
Total	$9	$65	$—
Balance at December 31, 2012:			
Accumulated OCI	$—	$7	$—
Net regulatory assets (liabilities)	13	342	5
Total	$13	$349	$5
Estimated amortization as net periodic postretirement benefit cost in 2014:			
Accumulated OCI	$—	$—	$—
Net regulatory assets (liabilities)	4	2	—
Total	$4	$2	$—

Table of Contents Index to Financial Statements

NOTES (continued)
Southern Company and Subsidiary Companies 2013 Annual Report

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, 2013 and 2012 are presented in the following table:

	Accumulated OCI	Net Regulatory Assets (Liabilities)
	(in millions)	
Balance at December 31, 2011	$6	$345
Net loss	1	35
Reclassification adjustments:		
Amortization of transition obligation	—	(10)
Amortization of prior service costs	—	(4)
Amortization of net gain (loss)	—	(6)
Total reclassification adjustments	—	(20)
Total change	1	15
Balance at December 31, 2012	$7	$360
Net gain	(6)	(266)
Reclassification adjustments:		
Amortization of transition obligation	—	(5)
Amortization of prior service costs	—	(4)
Amortization of net gain (loss)	—	(12)
Total reclassification adjustments	—	(21)
Total change	(6)	(287)
Balance at December 31, 2013	$1	$73

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

	2013	2012	2011
	(in millions)		
Service cost	$24	$21	$21
Interest cost	74	85	92
Expected return on plan assets	(56)	(60)	(64)
Net amortization	21	20	20
Net periodic postretirement benefit cost	$63	$66	$69

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)		
2014	$110	$(9)	$101
2015	115	(10)	105
2016	120	(11)	109
2017	124	(13)	111
2018	130	(14)	116
2019 to 2023	654	(75)	579

NOTES (continued)
Southern Company and Subsidiary Companies 2013 Annual Report

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, 2013 and 2012, along with the targeted mix of assets for each plan, is presented below:

	Target		2013		2012	
Pension plan assets:						
Domestic equity	26	%	31	%	28	%
International equity	25		25		24	
Fixed income	23		23		27	
Special situations	3		1		1	
Real estate investments	14		14		13	
Private equity	9		6		7	
Total	100	%	100	%	100	%
Other postretirement benefit plan assets:						
Domestic equity	40	%	40	%	38	%
International equity	21		25		24	
Domestic fixed income	25		24		28	
Global fixed income	4		4		3	
Special situations	1		—		—	
Real estate investments	6		5		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.

NOTES (continued)
Southern Company and Subsidiary Companies 2013 Annual Report

- 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, 2013 and 2012. 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.

Table of Contents Index to Financial Statements

The fair values of pension plan assets as of December 31, 2013 and 2012 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			
As of December 31, 2013:	Quoted Prices in Active Markets for Identical Assets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)	Total
	(in millions)			
Assets:				
Domestic equity*	$1,433	$839	$—	$2,272
International equity*	1,101	1,018	—	2,119
Fixed income:				
U.S. Treasury, government, and agency bonds	—	599	—	599
Mortgage- and asset-backed securities	—	156	—	156
Corporate bonds	—	978	—	978
Pooled funds	—	471	—	471
Cash equivalents and other	1	223	—	224
Real estate investments	260	—	1,000	1,260
Private equity	—	—	571	571
Total	$2,795	$4,284	$1,571	$8,650
Liabilities:				
Derivatives	—	(3)	—	(3)
Total	$2,795	$4,281	$1,571	$8,647

* 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.

Table of Contents Index to Financial Statements

NOTES (continued)
Southern Company and Subsidiary Companies 2013 Annual Report

As of December 31, 2012:	Fair Value Measurements Using Quoted Prices in Active Markets for Identical Assets (Level 1) (in millions)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)	Total
Assets:				
Domestic equity*	$1,163	$670	$—	$1,833
International equity*	912	979	—	1,891
Fixed income:				
U.S. Treasury, government, and agency bonds	—	516	—	516
Mortgage- and asset-backed securities	—	127	—	127
Corporate bonds	—	876	3	879
Pooled funds	—	399	—	399
Cash equivalents and other	5	548	—	553
Real estate investments	258	—	841	1,099
Private equity	—	—	593	593
Total	$2,338	$4,115	$1,437	$7,890

* 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.

Changes in the fair value measurement of the Level 3 items in the pension plan assets valued using significant unobservable inputs for the years ended December 31, 2013 and 2012 were as follows:

	2013 Real Estate Investments (in millions)	Private Equity	2012 Real Estate Investments	Private Equity
Beginning balance	$841	$593	$782	$582
Actual return on investments:				
Related to investments held at year end	74	8	56	1
Related to investments sold during the year	30	51	3	41
Total return on investments	104	59	59	42
Purchases, sales, and settlements	55	(81)	—	(31)
Ending balance	$1,000	$571	$841	$593

Table of Contents Index to Financial Statements

NOTES (continued)
Southern Company and Subsidiary Companies 2013 Annual Report

The fair values of other postretirement benefit plan assets as of December 31, 2013 and 2012 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			
As of December 31, 2013:	Quoted Prices in Active Markets for Identical Assets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)	Total
	(in millions)			
Assets:				
Domestic equity*	$157	$45	$—	$202
International equity*	39	82	—	121
Fixed income:				
U.S. Treasury, government, and agency bonds	—	34	—	34
Mortgage- and asset-backed securities	—	6	—	6
Corporate bonds	—	35	—	35
Pooled funds	—	46	—	46
Cash equivalents and other	—	19	—	19
Trust-owned life insurance	—	369	—	369
Real estate investments	10	—	36	46
Private equity	—	—	20	20
Total	$206	$636	$56	$898

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

NOTES (continued)
Southern Company and Subsidiary Companies 2013 Annual Report

As of December 31, 2012:	Fair Value Measurements Using Quoted Prices in Active Markets for Identical Assets (Level 1) (in millions)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)	Total
Assets:				
Domestic equity*	$140	$43	$—	$183
International equity*	33	75	—	108
Fixed income:				
U.S. Treasury, government, and agency bonds	—	24	—	24
Mortgage- and asset-backed securities	—	4	—	4
Corporate bonds	—	31	—	31
Pooled funds	—	42	—	42
Cash equivalents and other	—	44	—	44
Trust-owned life insurance	—	320	—	320
Real estate investments	10	—	30	40
Private equity	—	—	21	21
Total	$183	$583	$51	$817

* 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.

Changes in the fair value measurement of the Level 3 items in the other postretirement benefit plan assets valued using significant unobservable inputs for the years ended December 31, 2013 and 2012 were as follows:

	2013 Real Estate Investments (in millions)	Private Equity	2012 Real Estate Investments	Private Equity
Beginning balance	$30	$21	$30	$23
Actual return on investments:				
Related to investments held at year end	3	—	—	—
Related to investments sold during the year	1	2	—	1
Total return on investments	4	2	—	1
Purchases, sales, and settlements	2	(3)	—	(3)
Ending balance	$36	$20	$30	$21

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 2013, 2012, and 2011 were $84 million, $82 million, and $78 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 increased generally throughout the U.S. In particular, personal injury, property damage, and other claims for damages alleged to have been caused by carbon dioxide (CO_2) and other emissions, coal combustion residuals, and alleged exposure to hazardous materials, and/or requests for injunctive relief in connection with such matters, have become more frequent. 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.

Insurance Recovery

Mirant Corporation (Mirant) was an energy company with businesses that included independent power projects and energy trading and risk management companies in the U.S. and other countries. Mirant was a wholly-owned subsidiary of Southern Company until its initial public offering in 2000. In 2001, Southern Company completed a spin-off to its stockholders of its remaining ownership, and Mirant became an independent corporate entity.

In 2003, Mirant and certain of its affiliates filed voluntary petitions for relief under Chapter 11 of the Bankruptcy Code. In 2005, Mirant, as a debtor in possession, and the unsecured creditors' committee filed a complaint against Southern Company. Later in 2005, this complaint was transferred to MC Asset Recovery, LLC (MC Asset Recovery) as part of Mirant's plan of reorganization. In 2009, Southern Company entered into a settlement agreement with MC Asset Recovery to resolve this action. The settlement included an agreement where Southern Company paid MC Asset Recovery $202 million. Southern Company filed an insurance claim in 2009 to recover a portion of this settlement and received payments from its insurance provider of $25 million in June 2012 and $15 million on December 10, 2013. Additionally, legal fees related to these insurance settlements totaled approximately $6 million in 2012 and $4 million in 2013. As a result, the net reduction to expense presented as MC Asset Recovery insurance settlement in the statement of income was approximately $19 million in 2012 and $11 million in 2013.

Environmental Matters

New Source Review Actions

As part of a nationwide enforcement initiative against the electric utility industry which began in 1999, the EPA brought civil enforcement actions in federal district court against Alabama Power and Georgia Power alleging violations of the New Source Review (NSR) provisions of the Clean Air Act at certain coal-fired electric generating units, including units co-owned by Gulf Power and Mississippi Power. These civil actions seek penalties and injunctive relief, including orders requiring installation of the best available control technologies at the affected units. The case against Georgia Power (including claims related to a unit co-owned by Gulf Power) has been administratively closed in the U.S. District Court for the Northern District of Georgia since 2001. The case against Alabama Power (including claims involving a unit co-owned by Mississippi Power) has been actively litigated in the U.S. District Court for the Northern District of Alabama, resulting in a settlement in 2006 of the alleged NSR violations at Plant Miller; voluntary dismissal of certain claims by the EPA; and a grant of summary judgment for Alabama Power on all remaining claims and dismissal of the case with prejudice in 2011. On September 19, 2013, the U.S. Court of Appeals for the Eleventh Circuit affirmed in part and reversed in part the 2011 judgment in favor of Alabama Power, and the case has been transferred back to the U.S. District Court for the Northern District of Alabama for further proceedings.

Southern Company believes the traditional operating companies complied with applicable laws and regulations in effect at the time the work in question took place. The Clean Air Act authorizes maximum civil penalties of $25,000 to $37,500 per day, per violation, depending on the date of the alleged violation. An adverse outcome could require substantial capital expenditures that cannot be determined at this time and could possibly require payment of substantial penalties. Such expenditures could affect future results of operations, cash flows, and financial condition if such costs are not recovered through regulated rates. The ultimate outcome of these matters cannot be determined at this time.

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 properties. 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, 2013 was $18 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

NOTES (continued)
Southern Company and Subsidiary Companies 2013 Annual Report

Brunswick, Georgia on the CERCLA National Priorities List (NPL). The parties have completed the removal of wastes from the Brunswick site as ordered by the EPA. Additional cleanup and claims for recovery of natural resource damages at this site or for the assessment and potential cleanup of other sites are anticipated.
Georgia Power and numerous other entities have been designated by the EPA as PRPs at the Ward Transformer Superfund site located in Raleigh, North Carolina. In 2011, the EPA issued a Unilateral Administrative Order (UAO) to Georgia Power and 22 other parties, ordering specific remedial action of certain areas at the site. Later in 2011, Georgia Power filed a response with the EPA stating it has sufficient cause to believe it is not a liable party under CERCLA. The EPA notified Georgia Power in 2011 that it is considering enforcement options against Georgia Power and other non-complying UAO recipients. If the EPA pursues enforcement actions and the court determines that a respondent failed to comply with the UAO without sufficient cause, the EPA may also seek civil penalties of up to $37,500 per day for the violation and punitive damages of up to three times the costs incurred by the EPA as a result of the party's failure to comply with the UAO.
In addition to the EPA's action at this site, Georgia Power, along with many other parties, was sued in a private action by several existing PRPs for cost recovery related to the removal action. On February 1, 2013, the U.S. District Court for the Eastern District of North Carolina Western Division granted Georgia Power's summary judgment motion, ruling that Georgia Power has no liability in the private action. On May 10, 2013, the plaintiffs appealed the U.S. District Court for the Eastern District of North Carolina Western Division's order to the U.S. Court of Appeals for the Fourth Circuit.
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 the regulatory recovery mechanisms, 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 $50 million as of December 31, 2013. These estimated costs 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 will be subject to FDEP approval. The projects have been approved by the Florida PSC for recovery through Gulf Power's environmental cost recovery clause; therefore, there was no impact on net income as a result of these liabilities.
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 U.S. Department of Energy (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. The DOE failed to timely perform and has yet to commence the performance of its contractual and statutory obligation to dispose of spent nuclear fuel beginning no later than January 31, 1998. Consequently, Alabama Power and Georgia Power have pursued and continue to pursue legal remedies against the U.S. government for its partial breach of contract.
As a result of the first lawsuit, Georgia Power recovered approximately $27 million, based on its ownership interests, and Alabama Power recovered approximately $17 million, representing the vast majority of the Southern Company system's direct costs of the expansion of spent nuclear fuel storage facilities at Plants Farley and Hatch and Plant Vogtle Units 1 and 2 from 1998 through 2004. In April 2012, Alabama Power credited the award to cost of service for the benefit of customers. In July 2012, Georgia Power credited the award to accounts where the original costs were charged and used it to reduce rate base, fuel, and cost of service for the benefit of customers.

In 2008, Alabama Power and Georgia Power filed a second lawsuit 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. Damages are being sought for the period from January 1, 2005 through December 31, 2010. 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, 2013 for any potential recoveries from the second lawsuit. The final outcome of these matters cannot be determined at this time; however, no material impact on Southern Company's net income is expected.

An on-site dry storage facility at Plant Vogtle Units 1 and 2 began operation in October 2013. At Plants Hatch and Farley, on-site dry spent fuel storage facilities are also operational. Facilities at all plants can be expanded to accommodate spent fuel through the expected life of each plant.

Table of Contents Index to Financial Statements

Retail Regulatory Matters
Alabama Power
Retail Rate Adjustments
In 2011, the Alabama PSC issued an order to eliminate a tax-related adjustment under Alabama Power's rate structure effective with October 2011 billings. The elimination of this adjustment resulted in additional revenues of approximately $31 million for 2011. In accordance with the order, Alabama Power made additional accruals to the natural disaster reserve (NDR) in the fourth quarter 2011 of an amount equal to such additional 2011 revenues. The NDR was impacted as a result of operations and maintenance expenses incurred in connection with the 2011 storms in Alabama. See "Natural Disaster Reserve" below for additional information. The elimination of this adjustment resulted in additional revenues of approximately $106 million for 2012.
Rate RSE
Alabama Power operates under a rate stabilization and equalization plan (Rate RSE) approved by the Alabama PSC. Alabama Power's Rate RSE adjustments are based on forward-looking information for the applicable upcoming calendar year. Rate 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 equity return range, customer refunds will be required; however, there is no provision for additional customer billings should the actual retail return fall below the allowed equity return range. Prior to 2014, retail rates remained unchanged when the retail return on common equity (ROE) was projected to be between 13.0% and 14.5%.
During 2013, the Alabama PSC held public proceedings regarding the operation and utilization of Rate RSE. On August 13, 2013, the Alabama PSC voted to issue a report on Rate RSE that found that Alabama Power's Rate RSE mechanism continues to be just and reasonable to customers and Alabama Power, but recommended Alabama Power modify Rate RSE as follows:
- Eliminate the provision of Rate RSE establishing an allowed range of ROE.
- Eliminate the provision of Rate RSE limiting Alabama Power's capital structure to an allowed equity ratio of 45%.
- Replace these two provisions with a provision that establishes rates based upon an allowed weighted cost of equity (WCE) range of 5.75% to 6.21%, with an adjusting point of 5.98%. If calculated under the previous Rate RSE provisions, the resulting WCE would range from 5.85% to 6.53%, with an adjusting point of 6.19%.
- Provide 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.

Substantially all other provisions of Rate RSE were unchanged.
On August 21, 2013, Alabama Power filed its consent to these recommendations with the Alabama PSC. The changes became effective for calendar year 2014. On November 27, 2013, Alabama Power made its Rate RSE submission to the Alabama PSC of projected data for calendar year 2014; projected earnings were within the specified WCE range and, therefore, retail rates under Rate RSE remained unchanged for 2014. In 2012 and 2013, retail rates under Rate RSE remained unchanged from 2011. Under the terms of Rate RSE, the maximum possible increase for 2015 is 5.00%.
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 certificated new plant (Rate CNP). Alabama Power may also recover retail costs associated with certificated PPAs under rate certificated new plant (Rate CNP PPA). There was no adjustment to Rate CNP PPA in 2012. On March 5, 2013, 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, 2013 through March 31, 2014. It is anticipated that no adjustment will be made to Rate CNP PPA in 2014. As of December 31, 2013, Alabama Power had an under recovered certificated PPA balance of $18 million, all of which is included in deferred under recovered regulatory clause revenues in the balance sheet.

In 2011, the Alabama PSC approved and certificated a PPA of approximately 200 MWs of energy from wind-powered generating facilities which became operational in December 2012. In September 2012, the Alabama PSC approved and certificated a second wind PPA of approximately 200 MWs which became operational in January 2014. The terms of the wind PPAs permit Alabama Power to use the energy and retire the associated environmental attributes in service of its customers or to sell environmental attributes, separately or bundled with energy. Alabama Power has elected the normal purchase normal sale (NPNS) scope exception under the derivative accounting rules for its two wind PPAs, which total approximately 400 MWs. The NPNS

NOTES (continued)
Southern Company and Subsidiary Companies 2013 Annual Report

exception allows the PPAs to be recorded at a cost, rather than fair value, basis. The industry's application of the NPNS exception to certain physical forward transactions in nodal markets is currently under review by the U.S. Securities and Exchange Commission (SEC) at the request of the electric utility industry. The outcome of the SEC's review cannot now be determined. If Alabama Power is ultimately required to record these PPAs at fair value, an offsetting regulatory asset or regulatory liability will be recorded.

Alabama Power's retail rates, approved by the Alabama PSC also allows for the recovery of Alabama Power's retail costs associated with environmental laws, regulations, or other such mandates (Rate CNP Environmental). Rate CNP Environmental is based on forward-looking information and provides for the recovery of these costs pursuant to a factor that is calculated annually. Environmental costs to be recovered include operations and maintenance expenses, depreciation, and a return on certain invested capital. There was no adjustment to Rate CNP Environmental in 2012 or 2013. On August 13, 2013, the Alabama PSC approved Alabama Power's petition requesting a revision to Rate CNP Environmental that allows recovery of costs related to pre-2005 environmental assets previously being recovered through Rate RSE. The revenue impact as a result of this revision is estimated to be $58 million in 2014. On November 21, 2013, Alabama Power submitted calculations associated with its cost of complying with environmental mandates, as provided under Rate CNP Environmental. The filing reflected a projected unrecovered retail revenue requirement for environmental compliance of approximately $72 million, which is to be recovered in the billing months of January 2014 through December 2014. On December 3, 2013, the Alabama PSC issued a consent order that Alabama Power leave in effect for 2014 the factors associated with Alabama Power's environmental compliance costs for the year 2013. Any unrecovered amounts associated with 2014 will be reflected in the 2015 filing. As of December 31, 2013, Alabama Power had an under recovered environmental clause balance of $7 million which is included in deferred under recovered regulatory clause revenues in the balance sheet.

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 would be amortized over the affected unit's remaining useful life, as established prior to the decision regarding early retirement.

Compliance and Pension Cost Accounting Order

In November 2012, the Alabama PSC approved an accounting order to defer to a regulatory asset account certain compliance-related operations and maintenance expenditures for the years 2013 through 2017, as well as the incremental increase in operations expense related to pension cost for 2013. These deferred costs are to be amortized over a three-year period beginning in January 2015. The compliance related expenditures were related to (i) standards addressing Critical Infrastructure Protection issued by the North American Electric Reliability Corporation, (ii) cyber security requirements issued by the NRC, and (iii) NRC guidance addressing the readiness at nuclear facilities within the U.S. for severe events. The compliance-related expenses to be afforded regulatory asset treatment over the five-year period are currently estimated to be approximately $37 million. The amount of operations and maintenance expenses deferred to a regulatory asset in 2013 associated with compliance-related expenditures and pension cost was approximately $8 million and $12 million, respectively. Pursuant to the accounting order, Alabama Power has the ability to accelerate the amortization of the regulatory assets with notification to the Alabama PSC.

Retail Energy Cost Recovery

Alabama Power has established energy cost recovery rates under Alabama Power's energy cost recovery rate (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 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 kilowatt hour (KWH). On December 3, 2013, the Alabama PSC issued a consent order that Alabama Power leave in effect the energy cost recovery rates which began in April 2011 for 2014. Therefore, the Rate ECR factor as of January 1, 2014 remained at 2.681 cents per KWH. Effective with billings beginning in January 2015, the Rate ECR factor will be 5.910 cents per KWH, absent a further order from the Alabama PSC.

Alabama Power's over recovered fuel costs at December 31, 2013 totaled $42 million as compared to under recovered fuel costs of $4 million at December 31, 2012. At December 31, 2013, $27 million is included in other regulatory liabilities, current and $15 million is included in deferred over recovered regulatory clause revenues. The under recovered fuel costs at December 31, 2012 are included in deferred under recovered regulatory clause revenues in the balance sheets. These classifications are based on estimates, which include such factors as weather, generation availability, energy demand, and the price of energy. A change in any of these factors could have a material impact on the timing of any recovery of the under recovered fuel costs.

Natural Disaster Reserve

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 Natural Disaster Reserve (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.

In accordance with the order that was issued by the Alabama PSC in 2011 to eliminate a tax-related adjustment under Alabama Power's rate structure that resulted in additional revenues, Alabama Power made additional accruals to the NDR in the fourth quarter 2011 of an amount equal to the additional 2011 revenues, which were approximately $31 million.

The accumulated balances in the NDR for the years ended December 31, 2013 and December 31, 2012 were approximately $96 million and $103 million, respectively. Any accruals to the NDR are included in the balance sheets under other regulatory liabilities, deferred and are reflected as other operations and maintenance expenses in the statements of income.

Nuclear Outage Accounting Order

In accordance with a 2010 Alabama PSC order, nuclear outage operations and maintenance expenses for the two units at Plant Farley are deferred to a regulatory asset when the charges actually occur and are then amortized over the subsequent 18-month operational cycle.

Approximately $31 million of nuclear outage costs from the spring of 2012 was amortized to nuclear operations and maintenance expenses over the 18-month period ended in December 2013. During the spring of 2013, approximately $28 million of nuclear outage costs was deferred to a regulatory asset, and beginning in July 2013, these deferred costs are being amortized over an 18-month period. During the fall of 2013, approximately $32 million of nuclear outage costs associated with the second unit was deferred to a regulatory asset, and beginning in January 2014, these deferred costs are being amortized over an 18-month period. Alabama Power will continue the pattern of deferral of nuclear outage expenses as incurred and the recognition of expenses over a subsequent 18-month period pursuant to the Alabama PSC order.

Non-Nuclear Outage Accounting Order

On August 13, 2013, the Alabama PSC approved Alabama Power's petition requesting authorization to defer to a regulatory asset account certain operations and maintenance expenses associated with planned outages at non-nuclear generation facilities in 2014 and to amortize those expenses over a three-year period beginning in 2015. The 2014 outage expenditures to be deferred and amortized are estimated to total approximately $78 million.

NOTES (continued)
Southern Company and Subsidiary Companies 2013 Annual Report

Georgia Power
Rate Plans
In 2010, the Georgia PSC approved the 2010 ARP, which resulted in base rate increases of approximately $562 million, $17 million, $125 million, and $74 million effective January 1, 2011, January 1, 2012, April 1, 2012, and January 1, 2013, respectively.
On December 17, 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, which was filed with the Georgia PSC on November 18, 2013.
On January 1, 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 an additional $25 million; (3) Demand-Side Management (DSM) tariffs by an additional $1 million; and (4) Municipal Franchise Fee (MFF) tariff by an additional $4 million, for a total increase in base revenues of approximately $110 million.
Under the 2013 ARP, the following additional rate adjustments will be made to Georgia Power's tariffs in 2015 and 2016 based on annual compliance filings to be made at least 90 days prior to the effective date of the tariffs:

- Effective January 1, 2015 and 2016, the traditional base tariff rates will increase by an estimated $101 million and $36 million, respectively, to recover additional generation capacity-related costs;
- Effective January 1, 2015 and 2016, the ECCR tariff will increase by an estimated $76 million and $131 million, respectively, to recover additional environmental compliance costs;
- Effective January 1, 2015, the DSM tariffs will increase by an estimated $6 million and decrease by an estimated $1 million effective January 1, 2016; and
- The MFF tariff will increase consistent with these adjustments.

Georgia Power currently estimates these adjustments will result in base revenue increases of approximately $187 million in 2015 and $170 million in 2016. The estimated traditional base tariff rate increases for 2015 and 2016 do not include additional Qualifying Facility (QF) PPA expenses; however, compliance filings will include QF PPA expenses for those facilities that are projected to provide capacity to Georgia Power during the following year.
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. However, if at any time during the term of the 2013 ARP, Georgia Power projects that its retail earnings will be below 10.00% for any calendar year, it may petition the Georgia PSC for implementation of the Interim Cost Recovery (ICR) tariff that would be used to adjust Georgia Power's earnings back to a 10.00% retail ROE. The Georgia PSC would have 90 days to rule on Georgia Power's request. The ICR tariff will expire at the earlier of January 1, 2017 or the end of the calendar year in which the ICR tariff becomes effective. In lieu of requesting implementation of an ICR tariff, or if the Georgia PSC chooses not to implement the ICR tariff, Georgia Power may file a full rate case.
Except as provided above, Georgia Power will not file for a general base rate increase while the 2013 ARP is in effect. Georgia Power is required to file a general 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 Plans
On January 31, 2013, Georgia Power filed its triennial IRP (2013 IRP). The filing included Georgia Power's request to decertify 16 coal- and oil-fired units totaling 2,093 MWs. Several factors, including the cost to comply with existing and future environmental regulations, recent and forecasted economic conditions, and lower natural gas prices, contributed to the decision to close these units.
On April 17, 2013, the Georgia PSC approved the decertification of Plant Bowen Unit 6 (32 MWs), which was retired on April 25, 2013. On September 30, 2013, Plant Branch Unit 2 (319 MWs) was retired as approved by the Georgia

PSC in the 2011 Integrated Resource Plan Update (2011 IRP Update) in order to comply with the State of Georgia's Multi-Pollutant Rule.

On July 11, 2013, the Georgia PSC approved Georgia Power's request to decertify and retire Plant Boulevard Units 2 and 3 (28 MWs) effective July 17, 2013. Plant Branch Units 3 and 4 (1,016 MWs), Plant Yates Units 1 through 5 (579 MWs), and Plant McManus Units 1 and 2 (122 MWs) will be decertified and retired by April 16, 2015, the compliance date of the Mercury and Air Toxics Standards (MATS) rule. The decertification date of Plant Branch Unit 1 was extended from December 31, 2013 as specified in the final order in the 2011 IRP Update to coincide with the decertification date of Plant Branch Units 3 and 4. The decertification and retirement of Plant Kraft Units 1 through 4 (316 MWs) was also approved and will be effective by April 16, 2016, based on a one-year extension of the MATS rule compliance date that was approved by the State of Georgia Environmental Protection Division on September 10, 2013 to allow for necessary transmission system reliability improvements.

Additionally, the Georgia PSC approved Georgia Power's proposed MATS rule compliance plan for emissions controls necessary for the continued operation of Plants Bowen Units 1 through 4, Wansley Units 1 and 2, Scherer Units 1 through 3, and Hammond Units 1 through 4, the switch to natural gas as the primary fuel at Plant Yates Units 6 and 7 and Southern Electric Generating Company's (SEGCO) Plant Gaston Units 1 through 4, as well as the fuel switch at Plant McIntosh Unit 1 to operate on Powder River Basin coal.

In the 2013 ARP, the Georgia PSC approved the amortization of the construction work in progress (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 beginning in January 2014 and the amortization of any 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. The Georgia PSC deferred a decision regarding the appropriate recovery period for the costs associated with unusable materials and supplies remaining at the retiring plants to Georgia Power's next base rate case, which Georgia Power expects to file in 2016 (2016 Rate Case). In the 2013 IRP, the Georgia PSC also deferred decisions regarding the recovery of any fuel related costs that could be incurred in connection with the retirement units to be addressed in future fuel cases.

A request was filed with the Georgia PSC on January 10, 2014 to cancel the proposed biomass fuel conversion of Plant Mitchell Unit 3 (155 MWs) because it would not be cost effective for customers. The filing also notified the Georgia PSC of Georgia Power’s plans to seek decertification later this year. Plant Mitchell Unit 3 will continue to operate as a coal unit until April 2015 when it will be required to cease operation or install additional environmental controls to comply with the MATS rule. In connection with the retirement decision, Georgia Power reclassified the retail portion of the net carrying value of Plant Mitchell Unit 3 from plant in service, net of depreciation, to other utility plant, net.

The decertification of these units and fuel conversions are not expected to have a material impact on Southern Company's financial statements; however, the ultimate outcome depends on the Georgia PSC's order in the 2016 Rate Case and future fuel cases and cannot be determined at this time.

Renewables Development

On December 17, 2013, four PPAs totaling 50 MWs of utility scale solar generation under the Georgia Power Advanced Solar Initiative (GPASI) were approved by the Georgia PSC, with Georgia Power as the purchaser. These contracts will begin in 2015 and end in 2034. The resulting purchases will be for energy only and recovered through Georgia Power’s fuel cost recovery mechanism. Under the 2013 IRP, the Georgia PSC approved an additional 525 MWs of solar generation to be purchased by Georgia Power. The 525 MWs will be divided into 425 MWs of utility scale projects and 100 MWs of distributed generation.

On November 4, 2013, Georgia Power filed an application for the certification of two PPAs which were executed on April 22, 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.

During 2013, Georgia Power executed four PPAs to purchase a total of 169 MWs of biomass capacity and energy from four facilities in Georgia that will begin in 2015 and end in 2035. On May 21, 2013, the Georgia PSC approved two of the biomass PPAs and the remaining two were approved on December 17, 2013. The four biomass PPAs are contingent upon the counterparty meeting specified contract dates for posting collateral and commercial operation. The ultimate outcome of this matter cannot be determined at this time.

Fuel Cost Recovery

Georgia Power has established fuel cost recovery rates approved by the Georgia PSC. The Georgia PSC approved reductions in Georgia Power's total annual billings of approximately $43 million effective June 1, 2011, $567 million effective June 1, 2012, and $122 million effective January 1, 2013. The 2013 reduction was due to the Georgia PSC authorizing an Interim Fuel Rider, which is set to expire June 1, 2014. 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 revised and approved by the Georgia PSC on February 7, 2013, requiring it to use options and hedges within a 24-month time horizon. On February 18, 2014, the Georgia PSC approved the deferral of Georgia Power's next fuel case, which is now expected to be filed by March 1, 2015.

NOTES (continued)
Southern Company and Subsidiary Companies 2013 Annual Report

Georgia Power's over recovered fuel balance totaled approximately $58 million and $230 million at December 31, 2013 and 2012, respectively, and is included in current liabilities and other deferred credits and liabilities.
Fuel cost recovery revenues as recorded on the financial statements are adjusted for differences in actual recoverable fuel costs and amounts billed in current regulated rates. Accordingly, changes in the billing factor will not have a significant effect on Southern Company's revenues or net income, but will affect cash flow.

Storm Damage Recovery

Georgia Power defers and recovers certain costs related to damages from major storms as mandated by the Georgia PSC. As of December 31, 2013, the balance in the regulatory asset related to storm damage was $37 million. As a result of this regulatory treatment, the 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 (collectively, Owners), entered into an agreement with a consortium consisting of Westinghouse Electric Company LLC (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 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. Each 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%. The Vogtle 3 and 4 Agreement provides for liquidated damages upon the Contractor's failure to fulfill the schedule and performance guarantees. The Contractor's liability to the Owners for schedule and performance liquidated damages and warranty claims is subject to a cap.
Certain payment obligations of Westinghouse and Stone & Webster, Inc. under the Vogtle 3 and 4 Agreement are guaranteed by Toshiba Corporation and The Shaw Group, Inc., respectively. In the event of certain credit rating downgrades of any Owner, such Owner will be required to provide a letter of credit or other credit enhancement. The Owners may terminate the Vogtle 3 and 4 Agreement at any time for their convenience, provided that the Owners will be required to pay certain termination costs. The Contractor may terminate the Vogtle 3 and 4 Agreement under certain circumstances, including certain 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 Owners, 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, effective December 30, 2011, and issued combined construction and operating licenses (COLs) in February 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 are expected as construction proceeds.
In 2009, the Georgia PSC approved inclusion of the construction of two new nuclear generating units at Plant Vogtle (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 Nuclear Construction Cost Recovery (NCCR) tariff by including the related CWIP accounts in rate base during the construction period. The Georgia PSC approved increases to the NCCR tariff of approximately $223 million, $35 million, $50 million, and $60 million, effective January 1, 2011, 2012, 2013, and 2014, respectively.

Through the NCCR tariff, Georgia Power is collecting and amortizing to earnings approximately $91 million of financing costs, capitalized in 2009 and 2010, over the five-year period ending December 31, 2015, in addition to the ongoing financing costs. At December 31, 2013, approximately $37 million of these 2009 and 2010 costs remained unamortized in CWIP.

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 certified construction capital costs to be borne by Georgia Power increase by 5% 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. Accordingly, Georgia Power's eighth VCM report 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 and the fourth quarter 2018 for Plant Vogtle Units 3 and 4, respectively.

On September 3, 2013, the Georgia PSC approved a stipulation entered into by Georgia Power and the Georgia PSC staff to waive the requirement to amend the Plant Vogtle Units 3 and 4 certificate, until the commercial operation date of Plant Vogtle Unit 3, or earlier if deemed appropriate by the Georgia PSC and Georgia Power. In accordance with the Georgia Integrated Resource Planning Act, any costs incurred by Georgia Power in excess of the certified amount will not be included in rate base, unless shown to be reasonable and prudent. In addition, financing costs on any excess construction-related costs potentially would be subject to recovery through AFUDC instead of the NCCR tariff. As required by the stipulation, Georgia Power filed an abbreviated status update with the Georgia PSC on September 3, 2013, which reflected approximately $2.4 billion of total construction capital costs incurred through June 30, 2013. On October 15, 2013, the Georgia PSC voted to approve Georgia Power's eighth VCM report, reflecting construction capital costs incurred, which through December 31, 2012 totaled approximately $2.2 billion. Also in accordance with the stipulation, Georgia Power will file with the Georgia PSC on February 28, 2014 a combined ninth and tenth VCM report covering the period from January 1 through December 31, 2013 (Ninth/Tenth VCM report), which will request approval for an additional $0.4 billion of construction capital costs. The Ninth/Tenth VCM report will reflect estimated in-service construction capital costs of $4.8 billion and associated financing costs during the construction period, which are estimated to total approximately $2.0 billion. Georgia Power expects to resume filing semi-annual VCM reports in August 2014.

In July 2012, the Owners and the Contractor began negotiations 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 Owners are responsible for these costs under the terms of the Vogtle 3 and 4 Agreement. The portion of the additional costs claimed by the Contractor that would be attributable to Georgia Power (based on Georgia Power's ownership interest) with respect to these issues is approximately $425 million (in 2008 dollars). The Contractor also has asserted it is entitled to further schedule extensions. Georgia Power has not agreed with either the proposed cost or schedule adjustments or that the Owners have any responsibility for costs related to these issues. In November 2012, Georgia Power and the other Owners filed suit against the Contractor in the U.S. District Court for the Southern District of Georgia seeking a declaratory judgment that the Owners are not responsible for these costs. Also in November 2012, the Contractor filed suit against Georgia Power and the other Owners in the U.S. District Court for the District of Columbia alleging the Owners are responsible for these costs. On August 30, 2013, the U.S. District Court for the District of Columbia dismissed the Contractor's suit, ruling that the proper venue is the U.S. District Court for the Southern District of Georgia. The Contractor appealed the decision to the U.S. Court of Appeals for the District of Columbia Circuit on September 27, 2013. While litigation has commenced and Georgia Power intends to vigorously defend its positions, Georgia Power also expects negotiations with the Contractor to continue with respect to cost and schedule during which negotiations the parties may reach a mutually acceptable compromise of their positions.

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 are expected to 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 Owners, the Contractor, or both.

As construction continues, the risk remains that additional challenges in the fabrication, assembly, delivery, and installation of 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. Additional claims by the Contractor or Georgia Power (on behalf of the Owners) are also likely to arise throughout construction. These claims may be resolved through formal and informal dispute resolution procedures under the Vogtle 3 and 4 Agreement, but also may be resolved through litigation.

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

Gulf Power

Retail Base Rate Case

On December 3, 2013, the Florida PSC voted to approve the Settlement Agreement (Gulf Power Settlement Agreement) among Gulf Power and all of the intervenors to the docketed proceeding with respect to Gulf Power's request to increase retail base rates. Under the terms of the Gulf Power Settlement Agreement, Gulf Power (1) increased base rates designed to produce an additional $35 million in annual revenues effective January 2014 and will increase base rates designed to produce an additional $20 million in annual revenues effective January 2015; (2) continued its current authorized retail ROE midpoint and range; and (3) will accrue a return similar to AFUDC on certain transmission system upgrades that go into service after January 2014 until Gulf Power's next retail rate case or January 1, 2017, whichever comes first.

The Gulf Power Settlement Agreement also includes a self-executing adjustment mechanism that will increase the authorized 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 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 ROE, as reported to the Florida PSC monthly, to reach the midpoint of the authorized 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.

The Gulf Power Settlement Agreement also provides for recovery of costs associated with any tropical systems named by the National Hurricane Center through the initiation of a storm surcharge. The storm surcharge will begin, on an interim basis, 60 days following the filing of a cost recovery petition. The storm surcharge generally may not exceed $4.00/1,000 KWHs on monthly residential bills in aggregate for a calendar year. This limitation does not apply if Gulf Power incurs in excess of $100 million in storm recovery costs that qualify for recovery in a given calendar year. This threshold amount is inclusive of the amount necessary to replenish the storm reserve to the level that existed as of December 31, 2013.

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 integrated coal gasification combined cycle 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 on June 5, 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 Project Approval

In April 2012, the Mississippi PSC issued a detailed order confirming the certificate of public convenience and necessity (CPCN) originally approved by the Mississippi PSC in 2010 authorizing the acquisition, construction, and operation of the Kemper IGCC (2012 MPSC CPCN Order), which the Sierra Club appealed to the Chancery Court of Harrison County, Mississippi (Chancery Court). In December 2012, the Chancery Court affirmed the 2012 MPSC CPCN Order. On January 8, 2013, the Sierra Club filed an appeal of the Chancery Court's ruling with the Mississippi Supreme Court. The ultimate outcome of the CPCN challenge cannot be determined at this time.

Kemper IGCC Schedule and Cost Estimate

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 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. Exceptions to the $2.88 billion cost cap include 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 the ratepayers, relative to the original proposal for the CPCN) (Cost Cap Exceptions), as contemplated in the settlement agreement between Mississippi Power and the Mississippi PSC entered into on January 24, 2013 (Settlement Agreement) and the 2012 MPSC CPCN Order. Recovery of the Cost Cap Exception amounts remains subject to review and approval by the Mississippi PSC. The Kemper IGCC was originally scheduled to be placed in service in May 2014 and is currently scheduled to be placed in service in the fourth quarter 2014.

Table of Contents Index to Financial Statements

NOTES (continued)
Southern Company and Subsidiary Companies 2013 Annual Report

Mississippi Power's 2010 project estimate, current cost estimate, and actual costs incurred as of December 31, 2013 for the Kemper IGCC are as follows:

Cost Category	2010 Project Estimate[d]	Current Estimate	Actual Costs at 12/31/2013
	(in billions)		
Plant Subject to Cost Cap[a]	$2.40	$4.06	$3.25
Lignite Mine and Equipment	0.21	0.23	0.23
CO_2 Pipeline Facilities	0.14	0.11	0.09
AFUDC[b]	0.17	0.45	0.28
General Exceptions	0.05	0.10	0.07
Regulatory Asset[c]	—	0.09	0.07
Total Kemper IGCC[a]	$2.97	$5.04	$3.99

(a) 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.

(b) Mississippi Power's original estimate included recovery of financing costs during construction which was not approved by the Mississippi PSC in June 2012 as described in "Rate Recovery of Kemper IGCC Costs."

(c) 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."

(d) 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.

Of the total costs incurred as of December 31, 2013, $2.74 billion was included in CWIP (which is net of the DOE Grants and estimated probable losses of $1.18 billion), $70.5 million in other regulatory assets, and $3.9 million in other deferred charges and assets in the balance sheet, and $1.0 million was previously expensed.

Mississippi Power does not intend to seek any rate recovery or joint owner contributions for any related costs that exceed the $2.88 billion cost cap, excluding the Cost Cap Exceptions and net of the DOE Grants. Southern Company recorded pre-tax charges to income for revisions to the cost estimate of $1.2 billion ($729 million after-tax) in 2013. The revised cost estimates reflect increased labor costs, piping and other material costs, start-up costs, decreases in construction labor productivity, the change in the in-service date, and an increase in the contingency for risks associated with start-up activities.

Mississippi Power could experience further construction cost increases and/or schedule extensions with respect to the Kemper IGCC as a result of 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, or non-performance under construction or other agreements. Furthermore, Mississippi Power could also experience further schedule extensions associated with start-up activities for this "first-of-a-kind" technology, including major equipment failure, system integration, and operations, and/or unforeseen engineering problems, which would result in further cost increases and could result in the loss of certain tax benefits related to bonus depreciation. 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 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.

NOTES (continued)
Southern Company and Subsidiary Companies 2013 Annual Report

In June 2012, the Mississippi PSC denied Mississippi Power's proposed rate schedule for recovery of financing costs during construction, pending a final ruling from the Mississippi Supreme Court regarding the Sierra Club's appeal of the Mississippi PSC's issuance of the CPCN for the Kemper IGCC (2012 MPSC CWIP Order).
In July 2012, Mississippi Power appealed the Mississippi PSC's June 2012 decision to the Mississippi Supreme Court and requested interim rates under bond. In July 2012, the Mississippi Supreme Court denied Mississippi Power's request for interim rates under bond.
Settlement Agreement
On January 24, 2013, Mississippi Power entered into the Settlement Agreement with the Mississippi PSC that, among other things, establishes the process for resolving matters regarding cost recovery related to the Kemper IGCC and dismissed Mississippi Power's appeal of the 2012 MPSC CWIP Order. Under the 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. The Settlement Agreement also allows Mississippi Power to secure alternate financing for costs that are not otherwise recovered in any Mississippi PSC rate proceedings contemplated by the Settlement Agreement. 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 on February 26, 2013. Mississippi Power intends to securitize (1) prudently-incurred costs in excess of the certificated cost estimate and up to the $2.88 billion cost cap, net of the DOE Grants and excluding the Cost Cap Exceptions, (2) accrued AFUDC, and (3) other prudently-incurred costs as approved by the Mississippi PSC. The rate recovery necessary to recover the annual costs of securitization is expected to be filed and become effective after the Kemper IGCC is placed in service and following completion of the Mississippi PSC's final prudence review of costs for the Kemper IGCC.
The Settlement Agreement provides that Mississippi Power may terminate the Settlement Agreement if certain conditions are not met, if Mississippi Power is unable to secure alternate financing for any prudently-incurred Kemper IGCC costs not otherwise recovered in any Mississippi PSC rate proceeding contemplated by the Settlement Agreement, or if the Mississippi PSC fails to comply with the requirements of the Settlement Agreement. Mississippi Power continues to work with the Mississippi PSC and the Mississippi Public Utilities Staff to implement the procedural schedules set forth in the Settlement Agreement and variations to the schedule are likely.
2013 MPSC Rate Order
Consistent with the terms of the Settlement Agreement, on January 25, 2013, Mississippi Power filed a new request to increase retail rates in 2013 by $172 million annually, based on projected investment for 2013, to be recorded to a regulatory liability to be used to mitigate rate impacts when the Kemper IGCC is placed in service.
On March 5, 2013, the Mississippi PSC issued an order (2013 MPSC Rate Order) approving retail rate increases of 15% effective March 19, 2013 and 3% effective January 1, 2014, which collectively are designed to collect $156 million annually beginning in 2014. Amounts collected through these rates are being recorded as a regulatory liability to be used to mitigate customer rate impacts after the Kemper IGCC is placed in service. As of December 31, 2013, $98.1 million had been collected, with $10.3 million recognized in retail revenues in the statement of income and the remainder deferred in other regulatory liabilities and included in the balance sheet.
Because the 2013 MPSC Rate Order did not provide for the inclusion of CWIP in rate base as permitted by legislation designed to enhance the Mississippi PSC's authority to facilitate development and construction of baseload generation in the State of Mississippi (Baseload Act), Mississippi Power continues to record AFUDC on the Kemper IGCC during the construction period. 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. Mississippi Power will continue to comply with the 2013 MPSC Rate Order by collecting and deferring the approved rates during the construction period unless directed to do otherwise by the Mississippi PSC. On March 21, 2013, a legal challenge to the 2013 MPSC Rate Order was filed by Thomas A. Blanton with the Mississippi Supreme Court, which remains pending

against Mississippi Power and the Mississippi PSC.

Seven-Year Rate Plan

Also consistent with the Settlement Agreement, on February 26, 2013, Mississippi Power filed with the Mississippi PSC a rate recovery plan for the Kemper IGCC for the first seven years of its operation, along with a proposed revenue requirement under such plan for 2014 through 2020 (Seven-Year Rate Plan).

NOTES (continued)
Southern Company and Subsidiary Companies 2013 Annual Report

On March 22, 2013, Mississippi Power, in compliance with the 2013 MPSC Rate Order, filed a revision to the Seven-Year Rate Plan with the Mississippi PSC for the Kemper IGCC for cost recovery through 2020, which is still under review by the Mississippi PSC. In the Seven-Year Rate Plan, Mississippi Power proposed recovery of an annual revenue requirement of approximately $156 million of Kemper IGCC-related operational costs and rate base amounts, including plant costs equal to the $2.4 billion certificated cost estimate. The 2013 MPSC Rate Order, which increased rates beginning on March 19, 2013, is integral to the Seven-Year Rate Plan, which contemplates amortization of the regulatory liability balance at the in-service date to be used to mitigate customer rate impacts through 2020, based on a fixed amortization schedule that requires approval by the Mississippi PSC. Under the Seven-Year Rate Plan filing, Mississippi Power proposed annual rate recovery to remain the same from 2014 through 2020. At the time of the filing of the Seven-Year Rate Plan, the proposed revenue requirement approximated the forecasted cost of service for the period 2014 through 2020. Under Mississippi Power's proposal, to the extent that the actual annual cost of service differs from the forecast approved in the Seven-Year Rate Plan, the difference would be deferred as a regulatory asset or liability, subject to accrual of carrying costs, and would be included in the next year's rate recovery calculation. If any deferred balance remains at the end of the Seven-Year Rate Plan term, the Mississippi PSC will review the amount and determine the appropriate method and period of disposition.

The revenue requirements set forth in the Seven-Year Rate Plan assume the sale of a 15% undivided interest in the Kemper IGCC to South Mississippi Electric Power Association (SMEPA) and utilization of bonus depreciation as provided by the American Taxpayer Relief Act of 2012 (ATRA), which currently requires that the Kemper IGCC be placed in service in 2014. See "Investment Tax Credits and Bonus Depreciation" herein for additional information regarding bonus depreciation.

In 2014, Mississippi Power plans to amend the Seven-Year Rate Plan to reflect changes including the revised in-service date, the change in expected benefits relating to tax credits, various other revenue requirement items, and other tax matters, which include ensuring compliance with the normalization requirements of the Internal Revenue Code. The impact of these revisions for the average annual retail revenue requirement is estimated to be approximately $35 million through 2020. The amendment to the Seven-Year Rate Plan is also expected to reflect rate mitigation options identified by Mississippi Power that, if approved by the Mississippi PSC, would result in no change to the total customer rate impacts contemplated in the original Seven-Year Rate Plan.

Further cost increases and/or schedule extensions with respect to the Kemper IGCC could have an adverse impact on the Seven-Year Rate Plan, such as the inability to recover items considered as Cost Cap Exceptions, potential costs subject to securitization financing in excess of $1.0 billion, and the loss of certain tax benefits related to bonus depreciation. While the Kemper IGCC is scheduled to be placed in service in the fourth quarter 2014, any schedule extension beyond 2014 would result in the loss of the tax benefits related to bonus depreciation. The estimated value of the bonus depreciation tax benefits to retail customers is approximately $200 million. Loss of these tax benefits would require further adjustment to the Seven-Year Rate Plan and approval by the Mississippi PSC to ensure compliance with the normalization requirements of the Internal Revenue Code. In the event that the Mississippi PSC does not approve or Mississippi Power withdraws the Seven-Year Rate Plan, Mississippi Power would seek rate recovery through an alternate means, which could include a traditional rate case.

Prudence Reviews

The Mississippi PSC’s prudence review of Kemper IGCC costs incurred through March 31, 2013, as provided for in the Settlement Agreement, is expected to occur in the second quarter 2014. A final review of all costs incurred after March 31, 2013 is expected to be completed within six months of the Kemper IGCC’s in-service date. Furthermore, regardless of any prudence determinations made during the construction and start-up period, the Mississippi PSC has the right to make a final prudence determination after the Kemper IGCC has been placed in service.

Regulatory Assets

Consistent with the treatment of non-capital costs incurred during the pre-construction period, the Mississippi PSC granted Mississippi Power the authority to defer all non-capital Kemper IGCC-related costs to a regulatory asset during the construction period, subject to review of such costs by the Mississippi PSC. The amortization period for any such costs approved for recovery will be determined by the Mississippi PSC at a later date. 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.

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 on June 5, 2013.

NOTES (continued)
Southern Company and Subsidiary Companies 2013 Annual Report

In 2010, Mississippi Power executed a 40-year management fee contract with Liberty Fuels Company, LLC, a wholly-owned subsidiary of The North American Coal Corporation (Liberty Fuels), which will develop, construct, and manage 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. See Note 1 under "Asset Retirement Obligations and Other Costs of Removal" for additional information.

In addition, Mississippi Power will acquire, construct, and 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 ultimate outcome of these matters cannot be determined at this time.

Proposed Sale of Undivided Interest to SMEPA

In 2010, Mississippi Power and SMEPA entered into an asset purchase agreement whereby SMEPA agreed to purchase a 17.5% undivided interest in the Kemper IGCC. In February 2012, the Mississippi PSC approved the sale and transfer of 17.5% of the Kemper IGCC to SMEPA. In June 2012, Mississippi Power and SMEPA signed an amendment to the asset purchase agreement whereby SMEPA reduced its purchase commitment percentage from a 17.5% to a 15% undivided interest in the Kemper IGCC. On March 29, 2013, Mississippi Power and SMEPA signed an amendment to the asset purchase agreement whereby Mississippi Power and SMEPA agreed to amend the power supply agreement entered into by the parties in April 2011 to reduce the capacity amounts to be received by SMEPA by half (approximately 75 MWs) at the sale and transfer of the undivided interest in the Kemper IGCC to SMEPA. Capacity revenues under the April 2011 power supply agreement were $17.5 million in 2013. On December 24, 2013, Mississippi Power and SMEPA agreed to extend SMEPA's option to purchase through December 31, 2014. The sale and transfer of an interest in the Kemper IGCC to SMEPA is subject to approval by the Mississippi PSC.

The closing of this transaction is conditioned upon execution of a joint ownership and operating agreement, receipt of all construction permits, appropriate regulatory approvals, financing, and other conditions. In September 2012, SMEPA received a conditional loan commitment from Rural Utilities Service to provide funding for SMEPA's undivided interest in the Kemper IGCC.

In March 2012 and subsequent to December 31, 2013, Mississippi Power received $150 million and $75 million, respectively, of interest-bearing refundable deposits from SMEPA to be applied to the purchase. While the expectation is that these amounts will be applied to the purchase price at closing, Mississippi Power would be required to refund the deposits upon the termination of the asset purchase agreement, within 60 days of a request by SMEPA for a full or partial refund, or within 15 days at SMEPA's discretion in the event that Mississippi Power is assigned a senior unsecured credit rating of BBB+ or lower by Standard and Poor's Ratings Services, a division of The McGraw Hill Companies, Inc. (S&P) or Baa1 or lower by Moody's Investors Service, Inc. (Moody's) or ceases to be rated by either of these rating agencies. Given the interest-bearing nature of the deposit and SMEPA's ability to request a refund, the March 2012 deposit has been presented as a current liability in the balance sheet and as financing proceeds in the statement of cash flow. On July 18, 2013, Southern Company entered into an agreement with SMEPA under which Southern Company has agreed to guarantee the obligations of Mississippi Power with respect to any required refund of the deposits.

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

Baseload Act

In 2008, the Baseload Act was signed by the Governor of Mississippi. The Baseload Act authorizes, but does not require, the Mississippi PSC to adopt a cost recovery mechanism that includes in retail base rates, prior to and during construction, all or a portion of the prudently-incurred pre-construction and construction costs incurred by a utility in constructing a base load electric generating plant. Prior to the passage of the Baseload Act, such costs would traditionally be recovered only after the plant was placed in service. The Baseload Act also provides for periodic prudence reviews by the Mississippi PSC and prohibits the cancellation of any such generating plant without the approval of the Mississippi PSC. In the event of cancellation of the construction of the plant without approval of the Mississippi PSC, the Baseload Act authorizes the Mississippi PSC to make a public interest determination as to whether and to what extent the utility will be afforded rate recovery for costs incurred in connection with such cancelled generating plant. There are legal challenges to the constitutionality of the Baseload Act currently

NOTES (continued)
Southern Company and Subsidiary Companies 2013 Annual Report

pending before the Mississippi Supreme Court. The ultimate outcome of any legal challenges to this legislation cannot be determined at this time. See "Rate Recovery of Kemper IGCC Costs" herein for additional information.

Investment Tax Credits and Bonus Depreciation

The IRS allocated $133 million (Phase I) and $279 million (Phase II) of Internal Revenue Code Section 48A tax credits to Mississippi Power in connection with the Kemper IGCC. On May 15, 2013, the IRS notified Mississippi Power that no additional tax credits under the Internal Revenue Code Section 48A Phase III were allocated to the Kemper IGCC. As a result of the schedule extension for the Kemper IGCC, the Phase I credits have been recaptured. Through December 31, 2013, Mississippi Power had recorded tax benefits totaling $276.4 million for the remaining Phase II credits, which will be amortized as a reduction to depreciation and amortization over the life of the Kemper IGCC and are 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. A portion of the Phase II tax credits will be subject to recapture upon successful completion of SMEPA's purchase of an undivided interest in the Kemper IGCC as described above.

On January 2, 2013, the ATRA was signed into law. The ATRA retroactively extended several tax credits through 2013 and extended 50% bonus depreciation for property placed in service in 2013 (and for certain long-term production-period projects to be placed in service in 2014), which is expected to apply to the Kemper IGCC and have a positive impact on the future cash flows of Mississippi Power of between $560 million and $620 million in 2014. These estimated positive cash flow impacts are dependent upon placing the Kemper IGCC in service in 2014. See "Rate Recovery of Kemper IGCC Costs – Seven-Year Rate Plan" herein for additional information.

The ultimate outcome of these matters 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. 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, 2013, 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 %	$3,375	$2,028	$53
Plant Hatch (nuclear)	50.1	1,092	551	52
Plant Miller (coal) Units 1 and 2	91.8	1,410	575	89
Plant Scherer (coal) Units 1 and 2	8.4	209	80	24
Plant Wansley (coal)	53.5	800	260	36
Rocky Mountain (pumped storage)	25.4	182	120	—
Intercession City (combustion turbine)	33.3	14	4	—
Plant Stanton (combined cycle) Unit A	65.0	156	42	—

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, Georgia Power, and Southern Power have contracted to operate and maintain the jointly-owned facilities, except for Rocky Mountain and Intercession City, as agents for their respective co-owners. 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.

Table of Contents Index to Financial Statements

NOTES (continued)
Southern Company and Subsidiary Companies 2013 Annual Report

5. INCOME TAXES

Southern Company files a consolidated federal income tax return, combined state income tax returns for the States of Alabama, Georgia, and Mississippi, and unitary income tax returns for the States of California, North Carolina, and Texas. 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:

	2013	2012	2011
	(in millions)		
Federal —			
Current	$363	$177	$57
Deferred	386	1,011	1,035
	749	1,188	1,092
State —			
Current	(10)	61	8
Deferred	110	85	119
	100	146	127
Total	$849	$1,334	$1,219

Net cash payments/(refunds) for income taxes in 2013, 2012, and 2011 were $139 million, $38 million, and $(401) million, respectively.

NOTES (continued)
Southern Company and Subsidiary Companies 2013 Annual Report

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:

	2013	2012
	(in millions)	
Deferred tax liabilities —		
Accelerated depreciation	$9,710	$9,022
Property basis differences	1,515	1,254
Leveraged lease basis differences	287	278
Employee benefit obligations	491	536
Premium on reacquired debt	113	84
Regulatory assets associated with employee benefit obligations	705	988
Regulatory assets associated with asset retirement obligations	824	1,108
Other	350	349
Total	13,995	13,619
Deferred tax assets —		
Federal effect of state deferred taxes	421	394
Employee benefit obligations	1,048	1,678
Over recovered fuel clause	30	135
Other property basis differences	157	134
Deferred costs	84	39
ITC carryforward	121	256
Unbilled revenue	116	101
Other comprehensive losses	54	84
Asset retirement obligations	824	720
Estimated Loss on Kemper IGCC	472	—
Deferred state tax assets	77	68
Other	220	363
Total	3,624	3,972
Valuation allowance	(49)	(54)
Total deferred tax assets	3,575	3,918
Total deferred tax liabilities, net	10,420	9,701
Portion included in prepaid expenses (accrued income taxes), net	143	237
Accumulated deferred income taxes	$10,563	$9,938

At December 31, 2013, Southern Company had subsidiaries with State of Georgia net operating loss (NOL) carryforwards totaling $707 million, which could result in net state income tax benefits of $41 million, if utilized. However, the subsidiaries have established a valuation allowance for the potential $41 million tax benefit due to the remote likelihood that the tax benefit will be realized. These NOLs expire between 2018 and 2021. Beginning in 2002, the State of Georgia allowed Southern Company to file a combined return, which has prevented the creation of any additional NOL carryforwards.

At December 31, 2013, Southern Company had an ITC carryforward which is expected to result in $28 million of federal income tax benefit. The ITC carryforward expires in 2023, but is expected to be utilized in 2014. Additionally, Southern Company had a state ITC carryforward of $118 million, which will expire between 2020 and 2024.

At December 31, 2013, the tax-related regulatory assets to be recovered from customers were $1.4 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.

NOTES (continued)
Southern Company and Subsidiary Companies 2013 Annual Report

At December 31, 2013, the tax-related regulatory liabilities to be credited to customers were $202 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 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 $16 million in 2013, $23 million in 2012, and $19 million in 2011. At December 31, 2013, all ITCs available to reduce federal income taxes payable had not been utilized. The remaining ITCs will be carried forward and utilized in future years.

In 2010, the Tax Relief, Unemployment Insurance Reauthorization, and Job Creation Act of 2010 (Tax Relief Act) was signed into law. Major tax incentives in the Tax Relief Act include 100% bonus depreciation for property placed in service after September 8, 2010 and through 2011 (and for certain long-term production-period projects placed in service in 2012) and 50% bonus depreciation for property placed in service in 2012 (and for certain long-term production-period projects placed in service in 2013).

On January 2, 2013, ATRA was signed into law. The ATRA retroactively extended several tax credits through 2013 and extended 50% bonus depreciation for property placed in service in 2013 (and for certain long-term production-period projects to be placed in service in 2014, including the Kemper IGCC, which is scheduled for completion in 2014).

The application of the bonus depreciation provisions in these laws significantly increased deferred tax liabilities related to accelerated depreciation in 2013, 2012, and 2011.

Effective Tax Rate

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

	2013	2012	2011
Federal statutory rate	35.0 %	35.0 %	35.0 %
State income tax, net of federal deduction	2.5	2.5	2.4
Employee stock plans dividend deduction	(1.6)	(1.0)	(1.1)
Non-deductible book depreciation	1.5	0.9	0.7
AFUDC-Equity	(2.6)	(1.3)	(1.5)
ITC basis difference	(1.2)	(0.3)	(0.2)
Other	(0.5)	(0.2)	(0.3)
Effective income tax rate	33.1 %	35.6 %	35.0 %

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. Additionally, the 2013 effective rate decrease, as compared to 2012, is primarily due to an increase in non-taxable AFUDC equity. No material change occurred in the effective tax rate from 2011 to 2012.

Unrecognized Tax Benefits

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

	2013	2012	2011
	(in millions)		
Unrecognized tax benefits at beginning of year	$70	$120	$296
Tax positions from current periods	3	13	46
Tax positions increase from prior periods	—	7	1
Tax positions decrease from prior periods	(66)	(56)	(111)
Reductions due to settlements	—	(10)	(112)
Reductions due to expired statute of limitations	—	(4)	—
Balance at end of year	$7	$70	$120

The tax positions decrease from prior periods for 2013 relate primarily to the tax accounting method change for repairs-generation assets. See "Tax Method of Accounting for Repairs" herein for additional information.

NOTES (continued)
Southern Company and Subsidiary Companies 2013 Annual Report

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

	2013	2012	2011
	(in millions)		
Tax positions impacting the effective tax rate	$7	$5	$69
Tax positions not impacting the effective tax rate	—	65	51
Balance of unrecognized tax benefits	$7	$70	$120

The tax positions impacting the effective tax rate for 2013 primarily relate to state income tax credits. 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 as follows:

	2013	2012	2011
	(in millions)		
Interest accrued at beginning of year	$1	$10	$29
Interest reclassified due to settlements	—	(9)	(24)
Interest accrued during the year	—	—	5
Balance at end of year	$1	$1	$10

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 2011. Southern Company has filed its 2012 federal income tax return and has received a full acceptance letter from the IRS; however, the IRS has not finalized its audit. For tax years 2012 and 2013, Southern Company was 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 2007.

Tax Method of Accounting for Repairs

In 2011, the IRS published regulations on the deduction and capitalization of expenditures related to tangible property that generally apply for tax years beginning on or after January 1, 2014. Additionally, on April 30, 2013, the IRS issued Revenue Procedure 2013-24, which provides guidance for taxpayers related to the deductibility of repair costs associated with generation assets. Based on a review of the regulations, Southern Company incorporated provisions related to repair costs for generation assets into its consolidated 2012 federal income tax return and reversed all related unrecognized tax positions. On September 19, 2013, the IRS issued Treasury Decision 9636, "Guidance Regarding Deduction and Capitalization of Expenditures Related to Tangible Property," which are final tangible property regulations applicable to taxable years beginning on or after January 1, 2014. Southern Company is currently reviewing this new guidance. The ultimate outcome of this matter cannot be determined at this time; however, these regulations are not expected to have a material impact on the Company's financial statements.

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, 2013 and 2012, 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 each of December 31, 2013 and 2012, trust preferred securities of $200 million were outstanding.

NOTES (continued)
Southern Company and Subsidiary Companies 2013 Annual Report

Securities Due Within One Year
A summary of scheduled maturities and redemptions of securities due within one year at December 31 was as follows:

	2013	2012
	(in millions)	
Senior notes	$428	$2,085
Other long-term debt	12	227
Capitalized leases	29	23
Total	$469	$2,335

Maturities through 2018 applicable to total long-term debt are as follows: $469 million in 2014; $2.97 billion in 2015; $1.83 billion in 2016; $1.14 billion in 2017; and $880 million in 2018.
Bank Term Loans
Certain of the traditional operating companies have entered into various floating rate bank term loan agreements for loans bearing interest based on one-month London Interbank Offered Rate (LIBOR). At December 31, 2013, Georgia Power had outstanding bank term loans totaling $400 million, which are reflected in notes payable on the balance sheets. Also at December 31, 2013, Mississippi Power had outstanding bank term loans totaling $525 million, which are reflected in the statements of capitalization as long-term debt. At December 31, 2012, Mississippi Power had outstanding bank term loans totaling $175 million.
During 2013, the traditional operating companies repaid approximately $550 million of floating rate bank notes bearing interest based on one-month LIBOR.
During 2012, Mississippi Power entered into a 366-day $100 million aggregate principal amount floating rate bank loan bearing interest based on one-month LIBOR. The first advance in the amount of $50 million was made in November 2012. In January 2013, the second advance in the amount of $50 million was made. In September 2013, Mississippi Power amended the bank loan, which extended the maturity date to 2015. The proceeds of this loan were used for working capital and for other general corporate purposes, including Mississippi Power's continuous construction program.
In March 2013, Mississippi Power entered into four two-year floating rate bank loans bearing interest based on one-month LIBOR. These term loans were for an aggregate principal amount of $300 million and proceeds were used for working capital and other general corporate purposes, including Mississippi Power's continuous construction program.
In September 2013, Mississippi Power entered into a two-year floating rate bank loan bearing interest based on one-month LIBOR. The term loan was for $125 million aggregate principal amount and proceeds were used to repay at maturity a two-year floating rate bank loan in the aggregate principal amount of $125 million.
In November 2013, Georgia Power entered into three four-month floating rate bank loans for an aggregate principal amount of $400 million, bearing interest based on one-month LIBOR. The proceeds of these short-term loans were used for working capital and other general corporate purposes, including Georgia Power's continuous construction program. Subsequent to December 31, 2013, Georgia Power repaid these bank term loans.
Subsequent to December 31, 2013, Mississippi Power entered into an 18-month floating rate bank loan bearing interest based on one-month LIBOR. The term loan was for $250 million aggregate principal amount and proceeds were used for working capital and other general corporate purposes, including Mississippi Power’s continuous construction program.
These bank loans have 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 other hybrid securities and, for Mississippi Power, securitized debt relating to the securitization of certain costs of the Kemper IGCC. At December 31, 2013, Georgia Power and Mississippi Power were in compliance with their respective 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) on February 20, 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 Federal Financing Bank (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 will 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 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 in the event the DOE is required to make any payments to FFB under the DOE guarantee. Georgia Power's reimbursement obligations to the DOE are secured by a first priority lien on (i) Georgia Power's 45.7% undivided ownership interest in Plant Vogtle Units 3 and 4 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 December 31, 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%.

On February 20, 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 February 20, 2044 (the final maturity date) and the interest rate applicable to the remaining $500 million is 3.488% for an interest period that extends to February 20, 2029, and will be reset from time to time thereafter through the final maturity date. In connection with its entry into the Loan Guarantee Agreement, the FFB Note Purchase Agreement, and the FFB Promissory Note, Georgia Power incurred issuance costs of approximately $67 million, which will be amortized over the life of the borrowings under the FFB Credit Facility.

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, compliance with the Cargo Preference Act of 1954, 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 $2.1 billion of senior notes in 2013. Southern Company issued $500 million and its subsidiaries issued a total of $1.6 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.

At December 31, 2013 and 2012, Southern Company and its subsidiaries had a total of $17.3 billion and $17.4 billion, respectively, of senior notes outstanding. At December 31, 2013 and 2012, Southern Company had a total of $1.8 billion and $1.3 billion, respectively, of senior notes outstanding.

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.

NOTES (continued)
Southern Company and Subsidiary Companies 2013 Annual Report

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 \$3.2 billion and \$3.4 billion of outstanding pollution control revenue bonds at December 31, 2013 and 2012, 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 21, 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.
In March 2013 and July 2013, the Mississippi Business Finance Corporation (MBFC) issued \$15.8 million and \$15.3 million, respectively, aggregate principal amount of MBFC Taxable Revenue Bonds (Mississippi Power Company Project), Series 2012A. The proceeds were used to reimburse Mississippi Power for the cost of the acquisition, construction, equipping, installation, and improvement of certain equipment and facilities for the lignite mining facility related to the Kemper IGCC. In September 2013, the MBFC Taxable Revenue Bonds (Mississippi Power Company Project), Series 2012A of \$40.07 million, Series 2012B of \$21.25 million, and Series 2012C of \$21.25 million were paid at maturity.
In November 2013, the MBFC entered into an agreement to issue up to \$33.75 million aggregate principal amount of MBFC Taxable Revenue Bonds, Series 2013A (Mississippi Power Company Project) and up to \$11.25 million aggregate principal amount of MBFC Taxable Revenue Bonds, Series 2013B (Mississippi Power Company Project) for the benefit of Mississippi Power. In November 2013, the MBFC issued \$11.25 million aggregate principal amount of MBFC Taxable Revenue Bonds (Mississippi Power Company Project), Series 2013B for the benefit of Mississippi Power. The proceeds were used to reimburse Mississippi Power for the cost of the acquisition, construction, equipping, installation, and improvement of certain equipment and facilities for the lignite mining facility related to the Kemper IGCC. Any future issuances of the Series 2013A bonds will be used for this same purpose.
Mississippi Power had \$50.0 million of such obligations outstanding related to tax-exempt revenue bonds at December 31, 2013 and 2012 and \$11.3 million and \$51.5 million of such obligations related to taxable revenue bonds outstanding at December 31, 2013 and 2012, respectively. Such amounts are reflected in the statements of capitalization as long-term senior notes and debt.
Capital Leases
In September 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, 2013 of approximately \$83 million with an annual interest rate of 4.9%. Assets acquired under capital leases are recorded on the balance sheet as utility plant in service and the related obligations are classified as long-term debt.
At December 31, 2013 and 2012, the capitalized lease obligations for Georgia Power were \$45 million and \$50 million, respectively, with an interest rate of 7.9% for both years.
At December 31, 2013, 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, 2013 and 2012, a subsidiary of Southern Company had capital lease obligations of approximately $30 million in each period for certain computer equipment including desktops, laptops, servers, printers, and storage devices with interest rates that range from 1.4% to 3.2%.

Other Obligations

In March 2012 and subsequent to December 31, 2013, Mississippi Power received $150 million and $75 million, respectively, interest-bearing refundable deposits from SMEPA to be applied to the sale price for the pending sale of an undivided interest in

NOTES (continued)
Southern Company and Subsidiary Companies 2013 Annual Report

the Kemper IGCC. Until the sale is closed, the deposits bear interest at Mississippi Power's AFUDC rate adjusted for income taxes, which was 9.932% per annum for 2013 and 9.967% per annum for 2012, and are refundable to SMEPA upon termination of the asset purchase agreement related to such purchase, within 60 days of a request by SMEPA for a full or partial refund, or within 15 days at SMEPA's discretion in the event that Mississippi Power is assigned a senior unsecured credit rating of BBB+ or lower by S&P or Baa1 or lower by Moody's or ceases to be rated by either of these rating agencies. On July 18, 2013, Southern Company entered into an agreement with SMEPA under which Southern Company has agreed to guarantee the obligations of Mississippi Power with respect to any required refund of the deposits.

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. Alabama Power and Gulf Power have granted one or more liens on certain of their respective property in connection with the issuance of certain series of pollution control revenue bonds with an outstanding principal amount of $194 million as of December 31, 2013. 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.

In 2011, Mississippi Power purchased Plant Daniel Units 3 and 4 for approximately $85 million in cash and the assumption of $270 million face value (with a fair value on the assumption date of $346 million) of debt obligations of the lessor related to Plant Daniel Units 3 and 4, which mature in 2021 and bear interest at a fixed stated interest rate of 7.13% per annum. These obligations are secured by Plant Daniel Units 3 and 4 and certain personal property.

See "DOE Loan Guarantee Borrowings" for information regarding additional secured borrowings incurred by Georgia Power subsequent to December 31, 2013.

Bank Credit Arrangements

At December 31, 2013, committed credit arrangements with banks were as follows:

	Expires[a]						Executable Term Loans		Due Within One Year	
Company	2014	2015	2016	2018	Total	Unused	One Year	Two Years	Term Out	No Term Out
	(in millions)				(in millions)		(in millions)		(in millions)	
Southern Company	$—	$—	$—	$1,000	$1,000	$1,000	$—	$—	$—	$—
Alabama Power	238	35	—	1,030	1,303	1,303	53	—	53	185
Georgia Power	—	—	150	1,600	1,750	1,736	—	—	—	—
Gulf Power	110	—	165	—	275	275	45	—	45	65
Mississippi Power	135	—	165	—	300	300	25	40	65	70
Southern Power	—	—	—	500	500	500	—	—	—	—
Other	75	25	—	—	100	100	25	—	25	50
Total	$558	$60	$480	$4,130	$5,228	$5,214	$148	$40	$188	$370

(a) No credit arrangements expire in 2017.

Most of the 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. Compensating balances are not legally restricted from withdrawal.

Southern Company and its subsidiaries expect to renew their credit arrangements as needed, prior to expiration.
Most of the credit arrangements with banks have 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 Mississippi Power, securitized debt relating to the securitization of certain costs of the Kemper IGCC. At December 31, 2013, Southern Company, the traditional operating companies, and Southern Power were each in compliance with their respective debt limit covenants.
A portion of the $5.2 billion unused credit arrangements with banks is allocated to provide liquidity support to the traditional operating companies' variable rate pollution control revenue bonds and commercial paper programs. The amount of variable rate

NOTES (continued)
Southern Company and Subsidiary Companies 2013 Annual Report

pollution control revenue bonds requiring liquidity support as of December 31, 2013 was approximately $1.8 billion. In addition, at December 31, 2013, the traditional operating companies had $442 million of fixed rate pollution control revenue bonds that will be required to be remarketed within the next 12 months.

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

Details of short-term borrowings were as follows:

	Short-term Debt at the End of the Period[(a)]		
	Amount Outstanding	Weighted Average Interest Rate	
	(in millions)		
December 31, 2013:			
Commercial paper	$1,082	0.2	%
Short-term bank debt	400	0.9	%
Total	$1,482	0.4	%
December 31, 2012:			
Commercial paper	$820	0.3	%
Short-term bank debt	—	—	%
Total	$820	0.3	%

(a) Excludes notes payable related to other energy service contracts of $5 million at December 31, 2012.

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 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 that would allow the holders to elect a majority of such subsidiary's board. 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 required to be shown as "noncontrolling interest," separately presented as a component of "Stockholders' Equity" on Southern Company's balance sheets, statements of capitalization, and statements of stockholders' equity.

There were no changes for the years ended December 31, 2013 and 2012 in redeemable preferred stock of subsidiaries for Southern Company.

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 2013, 2012, and 2011, the traditional operating companies and Southern Power incurred fuel expense of $5.5 billion, $5.1 billion, and $6.3 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 $157 million, $171 million, and $199 million for 2013, 2012, and 2011, respectively.

NOTES (continued)
Southern Company and Subsidiary Companies 2013 Annual Report

Estimated total obligations under these commitments at December 31, 2013 were as follows:

	Capital Leases [4]	Operating Leases	Other
		(in millions)	
2014	$—	$201	$21
2015	20	244	13
2016	26	260	11
2017	27	263	8
2018	27	266	7
2019 and thereafter	541	2,104	58
Total	$641	$3,338	$118
Less: amounts representing executory costs [1]	142		
Net minimum lease payments	499		
Less: amounts representing interest [2]	166		
Present value of net minimum lease payments [3]	$333		

(1) Executory costs such as taxes, maintenance, and insurance (including the estimated profit thereon) are estimated and included in total minimum lease payments.

(2) Calculated Georgia Power's incremental borrowing rate at the inception of the leases.

(3) When the PPAs with non-affiliates begin in 2015, Georgia Power will recognize capital lease assets and capital lease obligations totaling $333 million, equal to the lesser of the present value of the net minimum lease payments or the estimated fair value of the leased property.

(4) A total of $1.3 billion of biomass PPAs included under the non-affiliate capital and operating leases is contingent upon the counterparty meeting specified contract dates for posting collateral and commercial operation.

Operating Leases

The Southern Company system has operating lease agreements with various terms and expiration dates. Total rent expense was $123 million, $155 million, and $176 million for 2013, 2012, and 2011, 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, 2013, estimated minimum lease payments under operating leases were as follows:

	Minimum Lease Payments		
	Barges & Railcars	Other	Total
	(in millions)		
2014	$56	$45	$101
2015	35	40	75
2016	30	35	65
2017	12	32	44
2018	6	25	31
2019 and thereafter	15	120	135
Total	$154	$297	$451

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 2023 with maximum obligations under these leases of $59 million. At the termination of the leases, the lessee may either 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.

NOTES (continued)
Southern Company and Subsidiary Companies 2013 Annual Report

Guarantees
As discussed above under "Operating Leases," Alabama Power and Georgia Power have entered into certain residual value guarantees.
8. COMMON STOCK
Stock Issued
During 2013, Southern Company issued approximately 6.9 million shares of common stock for $222.4 million through the employee and director stock plans, of which 0.7 million shares related to Southern Company's performance share plan.
During the first seven months of 2013, all sales under the Southern Investment Plan and the employee savings plan were funded with shares acquired on the open market by the independent plan administrators. Beginning in August 2013 and continuing through the fourth quarter 2013, Southern Company began using shares held in treasury to satisfy the requirements under the Southern Investment Plan and the employee savings plan, issuing a total of approximately 4.4 million shares of common stock previously held in treasury for approximately $183.6 million.
In addition, during the last six months of 2013, Southern Company issued approximately 8.0 million shares of common stock through at-the-market issuances pursuant to sales agency agreements related to Southern Company’s continuous equity offering program and received cash proceeds of approximately $327.3 million, net of $2.8 million in fees and commissions.
In 2012, Southern Company raised $397 million from the issuance of 12.1 million new common shares through the employee and director stock plans.
Stock Repurchased
In July 2012, Southern Company announced a program to repurchase shares to partially offset the incremental shares issued under its employee and director stock plans. There were no repurchases under this program in 2013 and no further repurchases under the program are anticipated.
Shares Reserved
At December 31, 2013, a total of 116 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 shares units as discussed below). Of the total 116 million shares reserved, there were 28 million shares of common stock remaining available for awards under the Omnibus Incentive Compensation Plan as of December 31, 2013.
Stock Options
Southern Company provides non-qualified stock options through its Omnibus Incentive Compensation Plan to a large segment of Southern Company system employees ranging from line management to executives. As of December 31, 2013, there were 5,776 current and former employees participating in the stock option program. The prices of options were at the fair market value of the shares on the dates of grant. These options become exercisable pro rata over a maximum period of three years from the date of grant. Southern Company generally recognizes stock option expense on a straight-line basis over the vesting period which equates to the requisite service period; however, for employees who are eligible for retirement, the total cost is expensed at the grant date. Options outstanding will expire no later than 10 years after the date of grant, unless terminated earlier by the Southern Company Board of Directors in accordance with the Omnibus Incentive Compensation Plan. Stock options held by employees of a company undergoing a change in control vest upon the change in control.
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.

Table of Contents Index to Financial Statements

NOTES (continued)
Southern Company and Subsidiary Companies 2013 Annual Report

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	2013	2012	2011
Expected volatility	16.6%	17.7%	17.5%
Expected term (in years)	5.0	5.0	5.0
Interest rate	0.9%	0.9%	2.3%
Dividend yield	4.4%	4.2%	4.8%
Weighted average grant-date fair value	$2.93	$3.39	$3.23

Southern Company's activity in the stock option program for 2013 is summarized below:

	Shares Subject to Option	Weighted Average Exercise Price
Outstanding at December 31, 2012	35,916,303	$36.37
Granted	9,152,716	44.17
Exercised	(6,078,735)	33.39
Cancelled	(170,918)	43.30
Outstanding at December 31, 2013	38,819,366	$38.64
Exercisable at December 31, 2013	24,150,442	$35.70

The number of stock options vested, and expected to vest in the future, as of December 31, 2013 was not significantly different from the number of stock options outstanding at December 31, 2013 as stated above. As of December 31, 2013, the weighted average remaining contractual term for the options outstanding and options exercisable was approximately six years and five years, respectively, and the aggregate intrinsic value for the options outstanding and options exercisable was $147 million and $142 million, respectively.

As of December 31, 2013, there was $9 million of total unrecognized compensation cost related to stock option awards not yet vested. That cost is expected to be recognized over a weighted-average period of approximately 11 months.

For the years ended December 31, 2013, 2012, and 2011, total compensation cost for stock option awards recognized in income was $25 million, $23 million, and $22 million, respectively, with the related tax benefit also recognized in income of $10 million, $9 million, and $8 million, respectively.

The total intrinsic value of options exercised during the years ended December 31, 2013, 2012, and 2011 was $77 million, $162 million, and $155 million, respectively. The actual tax benefit realized by the Company for the tax deductions from stock option exercises totaled $30 million, $62 million, and $60 million for the years ended December 31, 2013, 2012, and 2011, 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, 2013, 2012, and 2011 was $204 million, $397 million, and $528 million, respectively.

Performance Shares

Southern Company provides performance share award units through its Omnibus Incentive Compensation Plan to a large segment of Southern Company system employees ranging from line management to executives. The performance share units granted under the plan vest at the end of a three-year performance period which equates to the requisite service period. Employees that retire prior to the end of the three-year period receive a pro rata number of shares, issued at the end of the performance period, based on actual months of service prior to retirement. The value of the award units is based on Southern Company's total shareholder return (TSR) over the three-year performance period which measures Southern Company's relative performance against a group of industry peers. The performance shares are delivered in common stock following the end of the performance period based on Southern Company's actual TSR and may range from 0% to 200% of the original target performance share amount.

The fair value of performance share awards is determined as of the grant date using a Monte Carlo simulation model to estimate the TSR of Southern Company's 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. Compensation expense for awards where the service condition is met is recognized regardless of the actual number of shares issued. 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 award units.

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	2013	2012	2011
Expected volatility	12.0%	16.0%	19.2%
Expected term (in years)	3.0	3.0	3.0
Interest rate	0.4%	0.4%	1.4%
Annualized dividend rate	$1.96	$1.89	$1.82
Weighted average grant-date fair value	$40.50	$41.99	$35.97

Total unvested performance share units outstanding as of December 31, 2012 were 1,633,156. During 2013, 929,653 performance share units were granted, 807,702 performance share units were vested, and 111,348 performance share units were forfeited, resulting in 1,643,759 unvested units outstanding at December 31, 2013. In January 2014, the vested performance share award units were converted into 240,980 shares outstanding at a share price of $41.27 for the three-year performance and vesting period ended December 31, 2013.

For the years ended December 31, 2013, 2012, and 2011, total compensation cost for performance share units recognized in income was $31 million, $28 million, and $18 million, respectively, with the related tax benefit also recognized in income of $12 million, $11 million, and $7 million, respectively. As of December 31, 2013, there was $35 million of total unrecognized compensation cost related to performance share award units that will be recognized over a weighted-average period of approximately 11 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 were determined using the treasury stock method. Shares used to compute diluted earnings per share were as follows:

	Average Common Stock Shares		
	2013	2012	2011
	(in millions)		
As reported shares	877	871	857
Effect of options and performance share award units	4	8	7
Diluted shares	881	879	864

Stock options and performance share award units that were not included in the diluted earnings per share calculation because they were anti-dilutive were $16 million and were immaterial as of December 31, 2013 and 2012, respectively.

Common Stock Dividend Restrictions

The income of Southern Company is derived primarily from equity in earnings of its subsidiaries. At December 31, 2013, consolidated retained earnings included $6.1 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 $13.6 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 $252 million, respectively, per

NOTES (continued)
Southern Company and Subsidiary Companies 2013 Annual Report

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 to the financial statements herein 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 $500 million 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 $2.25 billion for nuclear losses in excess of the $500 million primary coverage. These policies have a sublimit of $1.7 billion for non-nuclear losses.

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 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 $43 million and $65 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.

Table of Contents Index to Financial Statements

NOTES (continued)
Southern Company and Subsidiary Companies 2013 Annual Report

As of December 31, 2013, assets and liabilities measured at fair value on a recurring basis during the period, together with the level of the fair value hierarchy in which they fall, were as follows:

	Fair Value Measurements Using			
As of December 31, 2013:	Quoted Prices in Active Markets for Identical Assets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)	Total
	(in millions)			
Assets:				
Energy-related derivatives	$—	$24	$—	$24
Interest rate derivatives	—	3	—	3
Nuclear decommissioning trusts:[(a)]				
Domestic equity	589	75	—	664
Foreign equity	35	196	—	231
U.S. Treasury and government agency securities	—	103	—	103
Municipal bonds	—	64	—	64
Corporate bonds	—	229	—	229
Mortgage and asset backed securities	—	132	—	132
Other investments	—	37	3	40
Cash equivalents	491	—	—	491
Other investments	9	—	4	13
Total	$1,124	$863	$7	$1,994
Liabilities:				
Energy-related derivatives	$—	$56	$—	$56

(a) 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.

NOTES (continued)
Southern Company and Subsidiary Companies 2013 Annual Report

As of December 31, 2012, assets and liabilities measured at fair value on a recurring basis during the period, together with the level of the fair value hierarchy in which they fall, were as follows:

	Fair Value Measurements Using			
As of December 31, 2012:	Quoted Prices in Active Markets for Identical Assets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)	Total
	(in millions)			
Assets:				
Energy-related derivatives	$—	$26	$—	$26
Interest rate derivatives	—	10	—	10
Nuclear decommissioning trusts:[(a)]				
Domestic equity	453	65	—	518
Foreign equity	28	172	—	200
U.S. Treasury and government agency securities	—	134	—	134
Municipal bonds	—	55	—	55
Corporate bonds	—	234	—	234
Mortgage and asset backed securities	—	141	—	141
Other investments	—	20	—	20
Cash equivalents	384	—	—	384
Other investments	9	—	15	24
Total	$874	$857	$15	$1,746
Liabilities:				
Energy-related derivatives	$—	$111	$—	$111

(a) 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 financial products valued using the market approach. Inputs for interest rate derivatives include LIBOR interest rates, interest rate futures contracts, and occasionally implied volatility of interest rate options. See Note 11 for additional information on how these derivatives are used.

For fair value measurements of investments within the nuclear decommissioning trusts, specifically the fixed income assets using significant other observable inputs and unobservable inputs, the primary valuation technique used is the market approach. External pricing vendors are designated for each of the asset classes in the nuclear decommissioning trusts with each security discriminately assigned a primary pricing source, based on similar characteristics.

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, 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' judgment are also obtained when available.

"Other investments" include investments in funds that are valued using the market approach and income approach. Securities that are traded in the open market are valued at the closing price on their principal exchange as of the measurement date. Discounts are applied in accordance with GAAP when certain trading restrictions exist. For investments that are not traded in the open

NOTES (continued)
Southern Company and Subsidiary Companies 2013 Annual Report

market, the price paid will have been determined based on market factors including comparable multiples and the expectations regarding cash flows and business plan execution. As the investments mature or if market conditions change materially, further analysis of the fair market value of the investment is performed. This analysis is typically based on a metric, such as multiple of earnings, revenues, earnings before interest and income taxes, or earnings adjusted for certain cash changes. These multiples are based on comparable multiples for publicly traded companies or other relevant prior transactions.
As of December 31, 2013 and 2012, the fair value measurements of investments calculated at net asset value per share (or its equivalent), as well as the nature and risks of those investments, were as follows:

	Fair Value	Unfunded Commitments	Redemption Frequency	Redemption Notice Period
As of December 31, 2013:	(in millions)			
Nuclear decommissioning trusts:				
Foreign equity funds	$131	None	Monthly	5 days
Corporate bonds – commingled funds	8	None	Daily	Not applicable
Equity – commingled funds	65	None	Daily/Monthly	Daily/7 days
Other – commingled funds	24	None	Daily	Not applicable
Trust-owned life insurance	110	None	Daily	15 days
Cash equivalents:				
Money market funds	491	None	Daily	Not applicable
As of December 31, 2012:				
Nuclear decommissioning trusts:				
Foreign equity funds	$117	None	Monthly	5 days
Corporate bonds – commingled funds	9	None	Daily	Not applicable
Equity – commingled funds	55	None	Daily/Monthly	Daily/7 days
Other – commingled funds	10	None	Daily	Not applicable
Trust-owned life insurance	96	None	Daily	15 days
Cash equivalents:				
Money market funds	384	None	Daily	Not applicable

The NRC requires licensees of commissioned nuclear power reactors to establish a plan for providing reasonable assurance of funds for future decommissioning. Alabama Power and Georgia Power have the Funds to comply with the NRC's regulations. The foreign equity fund in Georgia Power's nuclear decommissioning trusts seeks to provide long-term capital appreciation. In pursuing this investment objective, the foreign equity fund primarily invests in a diversified portfolio of equity securities of foreign companies, including those in emerging markets. These equity securities may include, but are not limited to, common stocks, preferred stocks, real estate investment trusts, convertible securities and depositary receipts, including American depositary receipts, European depositary receipts and global depositary receipts, and rights and warrants to buy common stocks. Georgia Power may withdraw all or a portion of its investment on the last business day of each month subject to a minimum withdrawal of $1 million, provided that a minimum investment of $10 million remains. If notices of withdrawal exceed 20% of the aggregate value of the foreign equity fund, then the foreign equity fund's board may refuse to permit the withdrawal of all such investments and may scale down the amounts to be withdrawn pro rata and may further determine that any withdrawal that has been postponed will have priority on the subsequent withdrawal date.
The commingled funds in Georgia Power's nuclear decommissioning trusts are invested primarily in a diversified portfolio including, but not limited to, commercial paper, notes, repurchase agreements, and other evidences of indebtedness with a maturity not exceeding 13 months from the date of purchase. The commingled funds will, however, generally maintain a dollar-weighted average portfolio maturity of 90 days or less. The assets may be longer term investment grade fixed income obligations with maturity shortening provisions. The primary objective for the

commingled funds is a high level of current income consistent with stability of principal and liquidity. The commingled funds included within corporate bonds represent the investment of cash collateral received under the Funds' managers' securities lending program that can only be sold upon the return of the loaned securities. See Note 1 under "Nuclear Decommissioning" for additional information.

NOTES (continued)
Southern Company and Subsidiary Companies 2013 Annual Report

Alabama Power's nuclear decommissioning trust includes investments in TOLI. The taxable nuclear decommissioning trust invests in the TOLI in order to minimize the impact of taxes on the portfolio and can draw on the value of the TOLI through death proceeds, loans against the cash surrender value, and/or the cash surrender value, subject to legal restrictions. The amounts reported in the table above reflect the fair value of investments the insurer has made in relation to the TOLI agreements. The nuclear decommissioning trust does not own the underlying investments, but the fair value of the investments approximates the cash surrender value of the TOLI policies. The investments made by the insurer are in commingled funds. The commingled funds primarily include investments in domestic and international equity securities and predominantly high-quality fixed income securities. These fixed income securities may include U.S. Treasury and government agency fixed income securities, non-U.S. government and agency fixed income securities, domestic and foreign corporate fixed income securities, and, to some degree, mortgage and asset backed securities. The passively managed funds seek to replicate the performance of a related index. The actively managed funds seek to exceed the performance of a related index through security analysis and selection.
The money market funds are short-term investments of excess funds in various money market mutual funds, which are portfolios of short-term debt securities. The money market funds are regulated by the Securities and Exchange Commission and typically receive the highest rating from credit rating agencies. Regulatory and rating agency requirements for money market funds include minimum credit ratings and maximum maturities for individual securities and a maximum weighted average portfolio maturity. Redemptions are available on a same day basis up to the full amount of the Company's investment in the money market funds.
As of December 31, 2013 and 2012, 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:		
2013	$21,650	$22,197
2012	$21,530	$23,480

The fair values are determined using Level 2 measurements and are based on quoted market prices for the same or similar issues or on the current rates offered 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, interest rate risk, and occasionally foreign currency 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. In the statements of cash flows, the cash impacts of settled energy-related and interest rate derivatives are recorded as operating activities and the cash impacts of settled foreign currency derivatives are recorded as investing 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. Southern Power has limited exposure to market volatility in commodity fuel prices and prices of electricity 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 contracts for the purchase and sale of electricity through the wholesale electricity market. To mitigate residual risks relative to movements in gas prices, the traditional operating companies and Southern Power may enter into fixed-price contracts for natural gas purchases; however, a significant portion of contracts are priced at market.

Table of Contents Index to Financial Statements

Energy-related derivative contracts are accounted for in 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 and 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, 2013, the net volume of energy-related derivative contracts for natural gas positions totaled 275 million mmBtu (million British thermal units) for the Southern Company system, with the longest hedge date of 2018 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 9 million mmBtu.

For cash flow hedges, the amounts expected to be reclassified from accumulated OCI to revenue and fuel expense for the next 12-month period ending December 31, 2014 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.

At December 31, 2013, 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, 2013
	(in millions)				(in millions)
Fair value hedges of existing debt					
	$ 350	4.15%	3-month LIBOR + 1.96%	May 2014	$ 3

The estimated pre-tax losses that will be reclassified from accumulated OCI to interest expense for the next 12-month period ending December 31, 2014 are immaterial. The Company has deferred gains and losses that are expected to be amortized into earnings through 2037.

Foreign Currency Derivatives

Southern Company and certain subsidiaries may enter into foreign currency derivatives to hedge exposure to changes in foreign currency exchange rates arising from purchases of equipment denominated in a currency other than U.S. dollars. Derivatives related to a firm commitment in a foreign currency transaction are accounted for as a fair value hedge where the derivatives' fair value gains or losses and the hedged items' fair value gains or losses are both recorded directly to earnings. Derivatives related to a forecasted transaction are accounted for as a cash flow hedge where the effective portion of the derivatives' fair value gains or

NOTES (continued)
Southern Company and Subsidiary Companies 2013 Annual Report

losses is recorded in OCI and is reclassified into earnings at the same time the hedged transactions affect earnings. Any ineffectiveness is recorded directly to earnings; however, Mississippi Power has regulatory approval allowing it to defer any ineffectiveness associated with firm commitments related to the Kemper IGCC to a regulatory asset. The derivatives employed as hedging instruments are structured to minimize ineffectiveness. At December 31, 2013, the fair value of the foreign currency derivative outstanding was immaterial.

Derivative Financial Statement Presentation and Amounts

At December 31, 2013 and 2012, the fair value of energy-related derivatives and interest rate derivatives was reflected in the balance sheets as follows:

Derivative Category	Asset Derivatives Balance Sheet Location	2013	2012	Liability Derivatives Balance Sheet Location	2013	2012
		(in millions)			(in millions)	
Derivatives designated as hedging instruments for regulatory purposes						
Energy-related derivatives:	Other current assets	$16	$10	Liabilities from risk management activities	$26	$74
	Other deferred charges and assets	7	13	Other deferred credits and liabilities	29	35
Total derivatives designated as hedging instruments for regulatory purposes		$23	$23		$55	$109
Derivatives designated as hedging instruments in cash flow and fair value hedges						
Interest rate derivatives:	Other current assets	$3	$7	Liabilities from risk management activities	$—	$—
	Other deferred charges and assets	—	3	Other deferred credits and liabilities	—	—
Total derivatives designated as hedging instruments in cash flow and fair value hedges		$3	$10		$—	$—
Derivatives not designated as hedging instruments						
Energy-related derivatives:	Other current assets	$—	$1	Liabilities from risk management activities	$1	$1
	Other deferred charges and assets	1	2	Other deferred credits and liabilities	—	1
Total derivatives not designated as hedging instruments		$1	$3		$1	$2
Total		$27	$36		$56	$111

All derivative instruments are measured at fair value. See Note 10 for additional information.

NOTES (continued)
Southern Company and Subsidiary Companies 2013 Annual Report

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 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 at December 31, 2013 and 2012 are presented in the following tables. Interest rate derivatives presented in the tables above do not have amounts available for offset and are therefore excluded from the offsetting disclosure tables below.

Fair Value					
Assets	2013	2012	Liabilities	2013	2012
	(in millions)			(in millions)	
Energy-related derivatives presented in the Balance Sheet [(a)]	$24	$26	Energy-related derivatives presented in the Balance Sheet [(a)]	$56	$111
Gross amounts not offset in the Balance Sheet [(b)]	(22)	(23)	Gross amounts not offset in the Balance Sheet [(b)]	(22)	(23)
Net-energy related derivative assets	$2	$3	Net-energy related derivative liabilities	$34	$88

(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, 2013 and 2012, the pre-tax effects of unrealized derivative gains (losses) arising from energy-related derivative instruments designated as regulatory hedging instruments and deferred on the balance sheets were as follows:

Derivative Category	Unrealized Losses Balance Sheet Location	2013	2012	Unrealized Gains Balance Sheet Location	2013	2012
		(in millions)			(in millions)	
Energy-related derivatives:	Other regulatory assets, current	$(26)	$(74)	Other regulatory liabilities, current	$16	$10
	Other regulatory assets, deferred	(29)	(35)	Other regulatory liabilities, deferred	7	13
Total energy-related derivative gains (losses)		$(55)	$(109)		$23	$23

For the years ended December 31, 2013, 2012, and 2011, the pre-tax effects of interest rate and foreign currency derivatives designated as fair value hedging instruments on the statements of income were immaterial on a gross basis for Southern Company. Furthermore, the pre-tax effects of interest rate derivatives designated as fair value hedging instruments on Southern Company's statements of income were offset by changes to the carrying value of long-term debt and the pre-tax effects of foreign currency derivatives designated as fair value hedging instruments on Southern Company's statements of income were offset by changes in the fair value of the purchase commitment related to equipment purchases.

For the years ended December 31, 2013, 2012, and 2011, the pre-tax effects of energy-related derivatives and interest rate derivatives designated as cash flow hedging instruments recorded in OCI and reclassified into earnings were immaterial for Southern Company.

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

For the Southern Company system's energy-related derivatives not designated as hedging instruments, a portion of the pre-tax realized and unrealized gains and losses is associated with hedging fuel price risk of certain PPA customers and has no impact on net income or on fuel expense as presented in the Company's statements of income. As a result, the pre-tax effects of energy-related derivatives not designated as hedging instruments on the Company's statements of income were immaterial for any year presented. This third party hedging activity has been discontinued.

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, 2013, the fair value of derivative liabilities with contingent features was $9 million.

NOTES (continued)
Southern Company and Subsidiary Companies 2013 Annual Report

At December 31, 2013, Southern Company's collateral posted with its derivative counterparties was immaterial. The maximum potential collateral requirements arising from the credit-risk-related contingent features, at a rating below BBB- and/or Baa3, were $9 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. 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 $346 million, $425 million, and $359 million in 2013, 2012, and 2011, 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, 2013, 2012, and 2011 was as follows:

NOTES (continued)
Southern Company and Subsidiary Companies 2013 Annual Report

	Electric Utilities Traditional Operating Companies (in millions)	Southern Power	Eliminations	Total	All Other	Eliminations	Consolidated
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	59,447	4,429	(101)	63,775	1,077	(306)	64,546
Gross property additions	5,226	633	—	5,859	9	—	5,868
2012							
Operating revenues	$15,730	$1,186	$(438)	$16,478	$141	$(82)	$16,537
Depreciation and amortization	1,629	143	—	1,772	15	—	1,787
Interest income	21	1	—	22	19	(1)	40
Interest expense	757	63	—	820	39	—	859
Income taxes	1,307	93	—	1,400	(66)	—	1,334
Segment net income (loss)[(a)]	2,145	175	1	2,321	33	(4)	2,350
Total assets	58,600	3,780	(129)	62,251	1,116	(218)	63,149
Gross property additions	4,813	241	—	5,054	5	—	5,059
2011							
Operating revenues	$16,763	$1,236	$(412)	$17,587	$149	$(79)	$17,657
Depreciation and amortization	1,576	124	—	1,700	16	1	1,717
Interest income	18	1	—	19	3	(1)	21
Interest expense	726	77	—	803	54	—	857
Income taxes	1,217	76	—	1,293	(74)	—	1,219
Segment net income (loss)[(a)]	2,052	162	—	2,214	(8)	(3)	2,203
Total assets	54,622	3,581	(127)	58,076	1,592	(401)	59,267
Gross property additions	4,589	255	—	4,844	9	—	4,853

(a) After dividends on preferred and preference stock of subsidiaries.
(b) Segment net income (loss) in 2013 includes $1.2 billion in pre-tax charges ($729 million after tax) for estimated probable losses on the Kemper IGCC.
See Note (3) under "Integrated Coal Gasification Combined Cycle – Kemper IGCC Construction Schedule and Cost Estimate" for additional information.

Products and Services
Electric Utilities' Revenues

Year	Retail (in millions)	Wholesale	Other	Total
2013	$14,541	$1,855	$639	$17,035
2012	14,187	1,675	616	16,478
2011	15,071	1,905	611	17,587

Table of Contents Index to Financial Statements

NOTES (continued)
Southern Company and Subsidiary Companies 2013 Annual Report

13. QUARTERLY FINANCIAL INFORMATION (UNAUDITED)

Summarized quarterly financial information for 2013 and 2012 is as follows:

Quarter Ended	Operating Revenues	Operating Income	Consolidated Net Income After Dividends on Preferred and Preference Stock of Subsidiaries	Per Common Share Basic Earnings	Diluted Earnings	Dividends	Trading Price Range High	Low
	(in millions)							
March 2013	$3,897	$325	$81	$0.09	$0.09	$0.4900	$46.95	$42.82
June 2013	4,246	640	297	0.34	0.34	0.5075	48.74	42.32
September 2013	5,017	1,491	852	0.97	0.97	0.5075	45.75	40.63
December 2013	3,927	799	414	0.47	0.47	0.5075	42.94	40.03
March 2012	$3,604	$766	$368	$0.42	$0.42	$0.4725	$46.06	$43.71
June 2012	4,181	1,143	623	0.71	0.71	0.4900	48.45	44.22
September 2012	5,049	1,740	976	1.11	1.11	0.4900	48.59	44.64
December 2012	3,703	814	383	0.44	0.44	0.4900	47.09	41.75

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

Table of Contents Index to Financial Statements

SELECTED CONSOLIDATED FINANCIAL AND OPERATING DATA
For the Periods Ended December 2009 through 2013
Southern Company and Subsidiary Companies 2013 Annual Report

	2013	2012	2011	2010		2009
Operating Revenues (in millions)	$17,087	$16,537	$17,657	$17,456		$15,743
Total Assets (in millions)	$64,546	$63,149	$59,267	$55,032		$52,046
Gross Property Additions (in millions)	$5,868	$5,059	$4,853	$4,443		$4,913
Return on Average Common Equity (percent)	8.82	13.10	13.04	12.71		11.67
Cash Dividends Paid Per Share of Common Stock	$2.0125	$1.9425	$1.8725	$1.8025		$1.7325
Consolidated Net Income After Dividends on Preferred and Preference Stock of Subsidiaries (in millions)	$1,644	$2,350	$2,203	$1,975		$1,643
Earnings Per Share —						
Basic	$1.88	$2.70	$2.57	$2.37		$2.07
Diluted	1.87	2.67	2.55	2.36		2.06
Capitalization (in millions):						
Common stock equity	$19,008	$18,297	$17,578	$16,202		$14,878
Preferred and preference stock of subsidiaries	756	707	707	707		707
Redeemable preferred stock of subsidiaries	375	375	375	375		375
Long-term debt	21,344	19,274	18,647	18,154		18,131
Total (excluding amounts due within one year)	$41,483	$38,653	$37,307	$35,438		$34,091
Capitalization Ratios (percent):						
Common stock equity	45.8	47.3	47.1	45.7		43.6
Preferred and preference stock of subsidiaries	1.8	1.8	1.9	2.0		2.1
Redeemable preferred stock of subsidiaries	0.9	1.0	1.0	1.1		1.1
Long-term debt	51.5	49.9	50.0	51.2		53.2
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	$21.43	$21.09	$20.32	$19.21		$18.15
Market price per share:						
High	$48.74	$48.59	$46.69	$38.62		$37.62
Low	40.03	41.75	35.73	30.85		26.48
Close (year-end)	41.11	42.81	46.29	38.23		33.32
Market-to-book ratio (year-end) (percent)	191.8	203.0	227.8	199.0		183.6
Price-earnings ratio (year-end) (times)	21.9	15.9	18.0	16.1		16.1
Dividends paid (in millions)	$1,762	$1,693	$1,601	$1,496		$1,369
Dividend yield (year-end) (percent)	4.9	4.5	4.0	4.7		5.2
Dividend payout ratio (percent)	107.1	72.0	72.7	75.7		83.3
Shares outstanding (in thousands):						
Average	876,755	871,388	856,898	832,189		794,795
Year-end	887,086	867,768	865,125	843,340		819,647
Stockholders of record (year-end)	143,800	149,628	155,198	160,426	*	92,799
Traditional Operating Company Customers (year-end) (in thousands):						
Residential	3,859	3,832	3,809	3,813		3,798

Commercial	583	580	579	580	580
Industrial	15	15	15	15	15
Other	10	9	9	9	9
Total	4,467	4,436	4,412	4,417	4,402
Employees (year-end)	26,300	26,439	26,377	25,940	26,112

* In July 2010, Southern Company changed its transfer agent from Southern Company Services, Inc. to Mellon Investor Services LLC (n/k/a Computershare Inc.). The change in the number of stockholders of record is primarily attributed to the calculation methodology used by Mellon Investor Services LLC.

Table of Contents Index to Financial Statements

SELECTED CONSOLIDATED FINANCIAL AND OPERATING DATA
For the Periods Ended December 2009 through 2013
Southern Company and Subsidiary Companies 2013 Annual Report

	2013	2012	2011	2010	2009
Operating Revenues (in millions):					
Residential	$6,011	$5,891	$6,268	$6,319	$5,481
Commercial	5,214	5,097	5,384	5,252	4,901
Industrial	3,188	3,071	3,287	3,097	2,806
Other	128	128	132	123	119
Total retail	14,541	14,187	15,071	14,791	13,307
Wholesale	1,855	1,675	1,905	1,994	1,802
Total revenues from sales of electricity	16,396	15,862	16,976	16,785	15,109
Other revenues	691	675	681	671	634
Total	$17,087	$16,537	$17,657	$17,456	$15,743
Kilowatt-Hour Sales (in millions):					
Residential	50,575	50,454	53,341	57,798	51,690
Commercial	52,551	53,007	53,855	55,492	53,526
Industrial	52,429	51,674	51,570	49,984	46,422
Other	902	919	936	943	953
Total retail	156,457	156,054	159,702	164,217	152,591
Wholesale sales	26,944	27,563	30,345	32,570	33,503
Total	183,401	183,617	190,047	196,787	186,094
Average Revenue Per Kilowatt-Hour (cents):					
Residential	11.89	11.68	11.75	10.93	10.60
Commercial	9.92	9.62	10.00	9.46	9.16
Industrial	6.08	5.94	6.37	6.20	6.04
Total retail	9.29	9.09	9.44	9.01	8.72
Wholesale	6.88	6.08	6.28	6.12	5.38
Total sales	8.94	8.64	8.93	8.53	8.12
Average Annual Kilowatt-Hour Use Per Residential Customer	13,144	13,187	13,997	15,176	13,607
Average Annual Revenue Per Residential Customer	$1,562	$1,540	$1,645	$1,659	$1,443
Plant Nameplate Capacity Ratings (year-end) (megawatts)	45,502	45,740	43,555	42,961	42,932
Maximum Peak-Hour Demand (megawatts):					
Winter	27,555	31,705	34,617	35,593	33,519
Summer	33,557	35,479	36,956	36,321	34,471
System Reserve Margin (at peak) (percent)	21.5	20.8	19.2	23.3	26.4
Annual Load Factor (percent)	63.2	59.5	59.0	62.2	60.6
Plant Availability (percent)*:					
Fossil-steam	87.7	89.4	88.1	91.4	91.3
Nuclear	91.5	94.2	93.0	92.1	90.1
Source of Energy Supply (percent):					
Coal	36.9	35.2	48.7	55.0	54.7

Nuclear	15.5	16.2	15.0	14.1	14.9
Hydro	3.9	1.7	2.1	2.5	3.9
Oil and gas	37.3	38.3	28.0	23.7	22.5
Purchased power	6.4	8.6	6.2	4.7	4.0
Total	100.0	100.0	100.0	100.0	100.0

* Beginning in 2012, plant availability is calculated as a weighted equivalent availability.

ALABAMA POWER COMPANY
FINANCIAL SECTION

MANAGEMENT'S REPORT ON INTERNAL CONTROL OVER FINANCIAL REPORTING
Alabama Power Company 2013 Annual Report
The management of Alabama Power Company (the Company) is responsible for establishing and maintaining an adequate system of internal control over financial reporting as required by the Sarbanes-Oxley Act of 2002 and as defined in Exchange Act Rule 13a-15(f). A control system can provide only reasonable, not absolute, assurance that the objectives of the control system are met.
Under management's supervision, an evaluation of the design and effectiveness of the Company's internal control over financial reporting was conducted based on the framework in Internal Control—Integrated Framework (1992) issued by the Committee of Sponsoring Organizations of the Treadway Commission. Based on this evaluation, management concluded that the Company's internal control over financial reporting was effective as of December 31, 2013.
/s/ Charles D. McCrary
Charles D. McCrary
President and Chief Executive Officer
/s/ Philip C. Raymond
Philip C. Raymond
Executive Vice President, Chief Financial Officer, and Treasurer
February 27, 2014

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM
To the Board of Directors of
Alabama Power Company

We have audited the accompanying balance sheets and statements of capitalization of Alabama Power Company (the Company) (a wholly owned subsidiary of The Southern Company) as of December 31, 2013 and 2012, and the related statements of income, comprehensive income, common stockholder's equity, and cash flows for each of the three years in the period ended December 31, 2013. These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements based on our audits.

We conducted our audits in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. The Company is not required to have, nor were we engaged to perform, an audit of its internal control over financial reporting. Our audits included consideration of internal control over financial reporting as a basis for designing audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the Company's internal control over financial reporting. Accordingly, we express no such opinion. An audit also includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

In our opinion, such financial statements (pages II-144 to II-191) present fairly, in all material respects, the financial position of Alabama Power Company as of December 31, 2013 and 2012, and the results of its operations and its cash flows for each of the three years in the period ended December 31, 2013, in conformity with accounting principles generally accepted in the United States of America.

/s/ Deloitte & Touche LLP
Birmingham, Alabama
February 27, 2014

MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS
Alabama Power Company 2013 Annual Report
OVERVIEW
Business Activities
Alabama Power Company (the Company) operates as a vertically integrated utility providing electricity to retail and wholesale customers within its traditional service territory located in the State of Alabama in addition to wholesale customers in the Southeast.
Many factors affect the opportunities, challenges, and risks of the Company's business of selling electricity. These factors include the ability to maintain a constructive regulatory environment, to maintain and grow energy sales given economic conditions, 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, and restoration following major storms. Appropriately balancing required costs and capital expenditures with customer prices will continue to challenge the Company for the foreseeable future.
Key Performance Indicators
The Company continues to focus on several key performance indicators. These indicators include customer satisfaction, plant availability, system reliability, and net income after dividends on preferred and preference stock.
The Company's financial success is directly tied to customer satisfaction. Key elements of ensuring customer satisfaction include outstanding service, high reliability, and competitive prices. Management uses customer satisfaction surveys and reliability indicators to evaluate the Company's results.
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 fossil/hydro 2013 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 performance for 2013 was better than the target for these reliability measures.
Net income after dividends on preferred and preference stock is the primary measure of the Company's financial performance. The Company's 2013 results compared to its targets for some of these key indicators are reflected in the following chart:

Key Performance Indicator	2013 Target Performance	2013 Actual Performance
Customer Satisfaction	Top quartile in customer surveys	Top quartile
Peak Season EFOR — fossil/hydro	5.86% or less	3.27%
Net Income After Dividends on Preferred and Preference Stock	$694 million	$712 million

See RESULTS OF OPERATIONS herein for additional information on the Company's financial performance.
Earnings
The Company's 2013 net income after dividends on preferred and preference stock of $712 million increased $8 million (1.1%) from the prior year. The increase in net income was due primarily to more favorable weather-related revenues in 2013 compared to 2012, an increase in allowance for funds used during construction (AFUDC) resulting from increased capital expenditures, and a decrease in interest expense resulting from lower interest rates. The factors increasing net income were partially offset by a decrease in revenues related to net investment under rate certificated new plant environmental (Rate CNP Environmental) and a decrease in wholesale revenues to municipalities.
The Company's 2012 net income after dividends on preferred and preference stock of $704 million decreased $4 million (0.6%) from the prior year. The decrease was due to decreases in weather-related revenues due to milder weather in 2012 compared to 2011 and an increase in other operations and maintenance expenses. The factors decreasing net income were partially offset by increases in revenues associated with the elimination of a tax-related

adjustment under the Company's rate structure effective in the fourth quarter 2011 and an increase in retail sales growth.

Table of Contents Index to Financial Statements

MANAGEMENT'S DISCUSSION AND ANALYSIS (continued)
Alabama Power Company 2013 Annual Report

RESULTS OF OPERATIONS

A condensed income statement for the Company follows:

	Amount	Increase (Decrease) from Prior Year	
	2013	2013	2012
	(in millions)		
Operating revenues	$5,618	$98	$(182)
Fuel	1,631	128	(176)
Purchased power	229	(26)	(16)
Other operations and maintenance	1,289	2	25
Depreciation and amortization	645	6	2
Taxes other than income taxes	348	8	1
Total operating expenses	4,142	118	(164)
Operating income	1,476	(20)	(18)
Allowance for equity funds used during construction	32	13	(3)
Interest income	16	—	(2)
Interest expense, net of amounts capitalized	259	(28)	(12)
Other income (expense), net	(36)	(12)	6
Income taxes	478	1	(1)
Net income	751	8	(4)
Dividends on preferred and preference stock	39	—	—
Net income after dividends on preferred and preference stock	$712	$8	$(4)

Operating Revenues

Operating revenues for 2013 were $5.6 billion, reflecting a $98 million increase from 2012. Details of operating revenues were as follows:

	Amount	
	2013	2012
	(in millions)	
Retail — prior year	$4,933	$4,972
Estimated change resulting from —		
Rates and pricing	(18)	69
Sales growth	4	61
Weather	21	(115)
Fuel and other cost recovery	12	(54)
Retail — current year	4,952	4,933
Wholesale revenues —		
Non-affiliates	248	277
Affiliates	212	111
Total wholesale revenues	460	388
Other operating revenues	206	199
Total operating revenues	$5,618	$5,520
Percent change	1.8%	(3.2)%

Retail revenues in 2013 were $5.0 billion. These revenues increased $19 million (0.4%) in 2013 and decreased $39 million (0.8%) in 2012, each as compared to the prior year. The increase in 2013 was due to more favorable weather, increased fuel revenues and

increased revenues associated with rate certificated new plant (Rate CNP PPA). The increase in 2013 was partially offset by a reduction in revenues related to net investments under Rate CNP Environmental. The decrease in 2012 was due to milder weather, a reduction in revenues related to net investments under Rate CNP Environmental, and a reduction in fuel revenues when compared to 2011. The decrease in 2012 was partially offset by increased revenues associated with the elimination of a tax-related adjustment under the Company's rate structure and weather adjusted sales growth due to higher demand. See FUTURE EARNINGS POTENTIAL – "PSC Matters" herein and Note 3 to the financial statements under "Retail Regulatory Matters" for additional information. See "Energy Sales" for a discussion of changes in the volume of energy sold, including changes related to sales growth (decline) and weather.

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

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

	2013	2012	2011
	(in millions)		
Capacity and other	$128	$143	$148
Energy	120	134	139
Total non-affiliated	$248	$277	$287

Wholesale revenues from sales to non-affiliates will vary depending on the market prices of available wholesale energy compared to the cost of the Company's and the Southern Company system's generation, demand for energy within the Southern Company system's service territory, and availability of the Southern Company system's generation. Increases and decreases in energy revenues that are driven by fuel prices are accompanied by an increase or decrease in fuel costs and do not have a significant impact on net income.

In 2013, wholesale revenues from sales to non-affiliates decreased $29 million (10.5%) reflecting a $15 million decrease in capacity revenues and a $14 million decrease in revenues from energy sales. In 2013, kilowatt-hour (KWH) sales decreased 11.3% primarily from decreased sales to municipalities, partially offset by an 0.8% increase in the price of energy. In 2012, wholesale revenues from sales to non-affiliates decreased $10 million (3.5%) reflecting a $5 million decrease in revenue from energy sales and a $5 million decrease in capacity revenues. In 2012, the price of energy decreased 5.2%, partially offset by a 1.8% increase in KWH sales. Short-term opportunity energy sales are also included in wholesale energy sales to non-affiliates. These opportunity sales are made at market-based rates that generally provide a margin above the Company's variable cost to produce the energy.

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

In 2013, wholesale revenues from sales to affiliates increased $101 million (91.0%) primarily due to a $103 million increase in energy sales, partially offset by a $2 million decrease in capacity revenues. In 2013, KWH sales increased 88.9% and there was a 1.3% increase in the price of energy. In 2012, wholesale revenues from sales to affiliates decreased $133 million (54.5%) primarily due to a $6 million decrease in capacity revenues and a $127 million decrease in energy sales. In 2012, KWH sales decreased 45% and there was a 17.6% decrease in the price of energy.

In 2013, other operating revenues were $206 million compared to $199 million in 2012. The increase from prior year revenues was not material.

Energy Sales

Changes in revenues are influenced heavily by the change in the volume of energy sold from year to year. KWH sales for 2013 and the percent change by year were as follows:

Table of Contents Index to Financial Statements

MANAGEMENT'S DISCUSSION AND ANALYSIS (continued)
Alabama Power Company 2013 Annual Report

	Total KWHs	Total KWH Percent Change		Weather-Adjusted Percent Change	
	2013	2013	2012	2013	2012
	(in billions)				
Residential	17.9	1.7%	(5.6)%	(1.1)%	2.6%
Commercial	13.9	(0.5)	(1.5)	0.5	0.6
Industrial	22.9	3.4	2.3	3.4	2.3
Other	0.2	(1.4)	—	(1.4)	—
Total retail	54.9	1.8	(1.4)	1.1%	1.9%
Wholesale —					
Non-affiliates	4.1	(10.8)	0.6		
Affiliates	7.3	88.9	(44.9)		
Total wholesale	11.4	34.5	(26.9)		
Total energy sales	66.3	6.3%	(5.9)%		

Changes in retail energy sales are comprised of changes in electricity usage by customers, changes in weather, and changes in the number of customers. Retail energy sales in 2013 were 1.8% more than in 2012. Residential sales increased 1.7%, due primarily to more favorable weather in 2013. Weather-adjusted residential sales decreased 1.1%, primarily due to a decrease in customer demand. Commercial sales and weather-adjusted commercial sales remained relatively flat in 2013. Industrial sales increased 3.4% in 2013 as a result of an increase in demand resulting from changes in production levels primarily in the chemicals, the primary metals, and the stone, clay, and glass sectors.
Retail energy sales in 2012 were 1.4% less than in 2011. Residential and commercial sales decreased 5.6% and 1.5%, respectively, due primarily to milder weather in 2012. Weather-adjusted residential sales increased 2.6%, primarily due to an increase in customer demand. Industrial sales increased 2.3% in 2012 as a result of increased customer demand, primarily in the pipelines, primary metals, chemicals, and automotive and plastics sectors, due to a recovering economy, partially offset by decreases in the textiles and stone, clay, and glass sectors.
See "Operating Revenues" above for a discussion of significant changes in wholesale revenues from sales to non-affiliates and wholesale revenues from sales to affiliated companies as related to changes in price and KWH sales.

Fuel and Purchased Power Expenses

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

MANAGEMENT'S DISCUSSION AND ANALYSIS (continued)
Alabama Power Company 2013 Annual Report

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

	2013	2012	2011
Total generation (billions of KWHs)	65.3	59.9	64.8
Total purchased power (billions of KWHs)	4.0	5.4	4.7
Sources of generation (percent) —			
Coal	53	53	56
Nuclear	21	25	22
Gas	17	18	17
Hydro	9	4	5
Cost of fuel, generated (cents per net KWH) —			
Coal	3.29	3.30	3.16
Nuclear	0.84	0.80	0.66
Gas	3.38	3.06	3.92
Average cost of fuel, generated (cents per net KWH)*	2.73	2.61	2.70
Average cost of purchased power (cents per net KWH)**	5.76	4.86	6.04

* KWHs generated by hydro are excluded from the average cost of fuel, generated.

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

Fuel and purchased power expenses were $1.9 billion in 2013, an increase of $102 million (5.8%) compared to 2012. The increase was primarily due to a $95 million increase in the volume of KWHs generated, a $38 million increase in the average cost of fuel, and a $37 million increase in the average cost of purchased power. These increases were partially offset by a $68 million decrease related to the volume of KWHs purchased.

Fuel and purchased power expenses were $1.8 billion in 2012, a decrease of $192 million (9.8%) compared to 2011. The decrease was primarily due to a $143 million decrease related to lower KWHs generated due to milder weather in 2012 compared to 2011 and a $92 million decrease in the cost of natural gas and the average cost of purchased power, partially offset by increases in the cost of coal and nuclear fuel.

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

Fuel

Fuel expenses were $1.6 billion in 2013, an increase of $128 million (8.5%) compared to 2012. This increase was primarily due to a 10.5% increase in the average cost of KWHs generated by natural gas, which excludes tolling agreements, and a 9.9% increase in KWHs generated by coal. This was partially offset by a 110.9% increase in the volume of KWHs generated by hydro facilities resulting from greater rainfall. Fuel expenses were $1.5 billion in 2012, a decrease of $176 million (10.5%) compared to 2011. This decrease was primarily due to a 21.9% decrease in the average cost of KWHs generated by natural gas, which excludes fuel associated with tolling agreements, and a 13.7% decrease in KWHs generated by coal, partially offset by 20.2% and 4.6% increases in the average cost of KWHs generated by nuclear fuel and coal, respectively.

Purchased Power – Non-Affiliates

In 2013, purchased power expense from non-affiliates was $100 million, an increase of $27 million (37.0%) compared to 2012. The increase over the prior year was primarily due to a 52.6% increase in the amount of energy purchased, partially offset by a 17.2% decrease in the average cost per KWH. In 2012 and 2011, purchased power expense from non-affiliates was $73 million.

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

MANAGEMENT'S DISCUSSION AND ANALYSIS (continued)
Alabama Power Company 2013 Annual Report

Purchased Power – Affiliates
Purchased power expense from affiliates was $129 million in 2013, a decrease of $53 million (29.1%) compared to 2012. This decrease was primarily due to a 50.4% decrease in the amount of energy purchased, partially offset by a 42.5% increase in the average cost per KWH. Purchased power expense from affiliates was $182 million in 2012, a decrease of $16 million (8.1%) compared to 2011. This decrease was primarily due to a 9.6% decrease in the average cost per KWH, partially offset by a 1.7% increase in the amount of energy purchased.
Energy purchases from affiliates will vary depending on demand for energy and the availability and cost of generating resources at each company within the Southern Company system. These purchases are made in accordance with the IIC or other contractual agreements, as approved by the FERC.
Other Operations and Maintenance Expenses
In 2013, other operations and maintenance expenses increased $2 million (0.22%) as compared to the prior year. The increase was not material.
In 2012, other operations and maintenance expenses increased $25 million (2.0%) as compared to the prior year. Administrative and general expenses increased $45 million primarily related to pension and other benefit-related expenses and injuries and damages expenses. Nuclear production expenses increased $23 million primarily related to the amortization of nuclear outage expenses of $35 million due to a change in the nuclear maintenance outage accounting process associated with routine refueling activities, as approved by the Alabama PSC in 2010. See FUTURE EARNINGS POTENTIAL – "PSC Matters – Nuclear Outage Accounting Order" herein for additional information. The increase in nuclear production expenses was partially offset by a decrease in operations costs related to labor expense. Other power generation expenses increased $6 million primarily related to scheduled outage costs and maintenance costs related to increases in labor and materials expenses. Transmission and distribution expenses decreased $32 million primarily related to a reduction in accruals to the natural disaster reserve (NDR). Steam production expenses decreased $22 million primarily related to a change in scheduled outage maintenance. See FUTURE EARNINGS POTENTIAL – "PSC Matters – Natural Disaster Reserve" herein for additional information.
Depreciation and Amortization
Depreciation and amortization increased $6 million (0.9%) in 2013 and $2 million (0.3%) in 2012, each as compared to the prior year. The increase in 2013 was primarily due to an increase in depreciation related to environmental assets, additions to property, plant, and equipment related to distribution and transmission projects, as well as the amortization of software. The increase related to environmental assets was offset by revenues under Rate CNP Environmental. These increases were partially offset by the deferral of certain expenses under an accounting order. See FUTURE EARNINGS POTENTIAL – "PSC Matters – Compliance and Pension Cost Accounting Order" herein and Note 3 to the financial statements under "Compliance and Pension Cost Accounting Order" for additional information. The increase in 2012 was not material.
Taxes Other Than Income Taxes
Taxes other than income taxes increased $8 million (2.4%) in 2013 and $1 million (0.3%) in 2012, each as compared to the prior year. The increase in 2013 was primarily due to property taxes, state use tax, and increases in municipal public utility license tax bases. The increase in 2012 was not material.
Allowance for Funds Used During Construction Equity
AFUDC equity increased $13 million (68.4%) in 2013 as compared to the prior year primarily due to increased capital expenditures associated with environmental, steam and nuclear generating facilities, and transmission. AFUDC equity decreased $3 million (13.6%) in 2012 as compared to the prior year primarily due to a decrease in capital expenditures associated with general plant projects and nuclear-related fuel and facilities. These decreases were primarily offset by increases in transmission and hydro generating facilities. See Note 1 to financial statements under "Allowance for Funds Used During Construction" for additional information.
Interest Expense, Net of Amounts Capitalized

Interest expense, net of amounts capitalized decreased $28 million (9.8%) in 2013 and $12 million (4.0%) in 2012, each as compared to the prior year. The decreases in 2013 and 2012 were primarily due to a decrease in interest rates and the timing of issuances and redemptions of long-term debt.

MANAGEMENT'S DISCUSSION AND ANALYSIS (continued)
Alabama Power Company 2013 Annual Report

Other Income (Expense), Net
Other income (expense), net decreased $12 million (50.0%) in 2013 as compared to the prior year primarily due to increases in donations, partially offset by increases in non-operating income related to gains on sales of non-utility property. Other income (expense), net increased $6 million (20.0%) in 2012 as compared to the prior year primarily due to an increase in non-operating income of $3 million, an increase in sales of property of $2 million, and a decrease in other deductions of $1 million.
Effects of Inflation
The Company is subject to rate regulation that is generally based on the recovery of historical and projected costs. The effects of inflation can create an economic loss since the recovery of costs could be in dollars that have less purchasing power. Any adverse effect of inflation on the Company's results of operations has not been substantial in recent years. See Note 3 to financial statements under "Retail Regulatory Matters – Rate RSE" for additional information.
FUTURE EARNINGS POTENTIAL
General
The Company operates as a vertically integrated utility providing electricity to retail and wholesale customers within its traditional service area located in the State of Alabama in addition to wholesale customers in the Southeast. Prices for electricity provided by the Company to retail customers are set by the Alabama PSC under cost-based regulatory principles. Prices for wholesale electricity sales, interconnecting transmission lines, and the exchange of electric power are regulated by the FERC. Retail rates and earnings are reviewed and may be adjusted periodically within certain limitations. See ACCOUNTING POLICIES – "Application of Critical Accounting Policies and Estimates – Electric Utility Regulation" and "FERC Matters" herein and Note 3 to the financial statements under "Retail Regulatory Matters" for additional information about regulatory matters.
The results of operations for the past three years are not necessarily indicative of future earnings potential. The level of the Company's future earnings depends on numerous factors that affect the opportunities, challenges, and risks of the Company's primary business of selling electricity. These factors include the Company's ability to maintain a constructive regulatory environment that continues to allow for the timely recovery of prudently-incurred costs during a time of increasing costs. Future earnings in the near term will depend, in part, upon maintaining energy sales which is subject to a number of factors. These factors include weather, competition, new energy contracts with other utilities, energy conservation practiced by customers, the price of electricity, the price elasticity of demand, and the rate of economic growth or decline in the Company's service territory. Changes in regional and global economic conditions impact sales for the Company, as the pace of the economic recovery remains uncertain. The timing and extent of the economic recovery will impact growth and may impact future earnings.
Environmental Matters
Compliance costs related to federal and state environmental statutes and regulations could affect earnings if such costs cannot continue to be fully recovered in rates on a timely basis. Environmental compliance spending over the next several years may differ materially from the amounts estimated. The timing, specific requirements, and estimated costs could change as environmental statutes and regulations are adopted or modified. 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.
New Source Review Actions
As part of a nationwide enforcement initiative against the electric utility industry which began in 1999, the U.S. Environmental Protection Agency (EPA) brought civil enforcement actions in federal district court against the Company alleging violations of the New Source Review (NSR) provisions of the Clean Air Act at certain coal-fired electric generating units, including a unit co-owned by Mississippi Power. These civil actions seek penalties and injunctive relief, including orders requiring installation of the best available control technologies at the affected units.

The case against the Company (including claims involving a unit co-owned by Mississippi Power) has been actively litigated in the U.S. District Court for the Northern District of Alabama, resulting in a settlement in 2006 of the alleged NSR violations at Plant Miller; voluntary dismissal of certain claims by the EPA; and a grant of summary judgment for the Company on all remaining claims and dismissal of the case with prejudice in 2011. On September 19, 2013, the U.S. Court of Appeals for the Eleventh Circuit affirmed in part and reversed in part the 2011 judgment in favor of the Company, and the case has been transferred back to the U.S. District Court for the Northern District of Alabama for further proceedings.

The Company believes it complied with applicable laws and regulations in effect at the time the work in question took place. The Clean Air Act authorizes maximum civil penalties of $25,000 to $37,500 per day, per violation, depending on the date of the alleged violation. An adverse outcome could require substantial capital expenditures that cannot be determined at this time and could possibly require payment of substantial penalties. Such expenditures could affect future results of operations, cash flows, and financial condition if such costs are not recovered through regulated rates. The ultimate outcome of this matter cannot be determined at this time.

Environmental Statutes and Regulations

General

The Company's operations are subject to extensive regulation by state and federal environmental agencies under a variety of statutes and regulations governing environmental media, including air, water, and land resources. Applicable statutes include the Clean Air Act; the Clean Water Act; the Comprehensive Environmental Response, Compensation, and Liability Act; the Resource Conservation and Recovery Act; the Toxic Substances Control Act; the Emergency Planning & Community Right-to-Know Act; the Endangered Species Act; 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 2013, the Company had invested approximately $3.2 billion in environmental capital retrofit projects to comply with these requirements, with annual totals of approximately $184 million, $62 million, and $34 million for 2013, 2012, and 2011, respectively. The Company expects that base level capital expenditures to comply with existing statutes and regulations will total approximately $1.1 billion from 2014 through 2016, with annual totals of approximately $502 million, $443 million, and $166 million for 2014, 2015, and 2016, respectively.

The Company continues to monitor the development of the EPA's proposed water and coal combustion residuals rules and to evaluate compliance options. See FINANCIAL CONDITION AND LIQUIDITY – "Capital Requirements and Contractual Obligations" herein for the Company's anticipated incremental compliance costs related to the proposed water and coal combustion residuals rules for 2014 through 2016. The ultimate capital expenditures and compliance costs with respect to these proposed rules, including additional expenditures required after 2016, will be dependent on the requirements of the final rules and regulations adopted by the EPA and the outcome of any legal challenges to these rules. See "Water Quality" and "Coal Combustion Residuals" herein for additional information.

The Company's ultimate environmental compliance strategy, including potential unit retirement and replacement decisions, and future environmental capital expenditures will be affected by the final requirements of new or revised environmental regulations and regulations relating to global climate change that are promulgated, including the proposed 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 Company's fuel mix. Compliance costs may arise from existing unit retirements, installation of additional environmental controls, upgrades to the transmission system, and adding or changing fuel sources for certain existing units. The ultimate outcome of these matters cannot be determined at this time.

Southern Electric Generating Company (SEGCO), a subsidiary of the Company, is jointly owned with Georgia Power. As part of its environmental compliance strategy, SEGCO plans to add natural gas as the primary fuel source for its generating units in 2015. The capacity of SEGCO's units is sold equally to the Company and Georgia Power through a power purchase agreement (PPA). If such compliance costs cannot continue to be recovered through retail rates, they could have a material financial impact on the Company's financial statements. See Note 4 to the financial statements for additional information.

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

Air Quality

Compliance with the Clean Air Act and resulting regulations has been and will continue to be a significant focus for the Company. Since 1990, the Company has spent approximately $2.7 billion in reducing and monitoring emissions pursuant to the Clean Air Act. Additional controls are currently planned or under consideration to further reduce air emissions, maintain compliance with existing regulations, and meet new requirements.

MANAGEMENT'S DISCUSSION AND ANALYSIS (continued)
Alabama Power Company 2013 Annual Report

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 more stringent eight-hour ozone NAAQS, which it began to implement in 2011. In May 2012, the EPA published its final determination of nonattainment areas based on the 2008 eight-hour ozone NAAQS. All areas within the Company's service territory have achieved attainment of this standard.

The EPA regulates fine particulate matter concentrations on an annual and 24-hour average basis. All areas within the Company's service territory have achieved attainment with the 1997 and 2006 particulate matter NAAQS, and the EPA has officially redesignated some former nonattainment areas within the service territory as attainment for these standards. On January 15, 2013, the EPA published a final rule that increases the stringency of the annual fine particulate matter standard. The new standard could result in the designation of new nonattainment areas within the Company's service territory.

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 Company's service territory have been designated as nonattainment under this rule. However, the EPA may designate additional areas as nonattainment in the future, which could include areas within the Company's service territory. Implementation of the revised SO_2 standard could require additional reductions in SO_2 emissions and increased compliance and operational costs.

On February 13, 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. On March 6, 2013, the U.S. Court of Appeals for the Eleventh Circuit ruled in favor of the Company and vacated an earlier attempt by the EPA to rescind its 2008 approval. The EPA’s latest proposal characterizes the proposed deletion as an error correction within the meaning of the Clean Air Act. The Company believes this interpretation of the Clean Air Act to be incorrect. If finalized, this proposed action could affect unit availability and result in increased operations and maintenance costs for affected units, including units co-owned by Mississippi Power and units owned by SEGCO.

The Company's service territory is subject to the requirements of the Clean Air Interstate Rule (CAIR), which calls for phased reductions in SO_2 and nitrogen oxide (NO_x) emissions from power plants in 28 eastern states. In 2008, the U.S. Court of Appeals for the District of Columbia Circuit issued decisions invalidating CAIR, but left CAIR compliance requirements in place while the EPA developed a new rule. In 2011, the EPA promulgated the Cross State Air Pollution Rule (CSAPR) to replace CAIR. However, in August 2012, the U.S. Court of Appeals for the District of Columbia Circuit vacated CSAPR in its entirety and directed the EPA to continue to administer CAIR pending the EPA's development of a valid replacement. Review of the U.S. Court of Appeals for the District of Columbia Circuit's decision regarding CSAPR is currently pending before the U.S. Supreme Court.

The EPA finalized the Clean Air Visibility Rule (CAVR) 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 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 February 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. Compliance for existing sources is required by April 16, 2015; however, states may authorize a compliance extension of up to one year to April 16, 2016.

In August 2012, the EPA published proposed revisions to the New Source Performance Standard (NSPS) for Stationary Combustion Turbines (CTs). 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 February 12, 2013, the EPA proposed a rule that would require certain states to revise the provisions of their SIPs relating to the regulation of excess emissions at industrial facilities, including fossil-fuel fired generating facilities, during periods of startup, shut-down, or malfunction (SSM). The EPA proposes a determination that the SSM provisions in the SIPs for 36 states, including Alabama, do not meet the requirements of the Clean Air Act and must be revised within 18 months of the date on which the EPA publishes the final rule. The EPA has entered into a settlement agreement requiring it to finalize the rule by June 12, 2014.

The Company has developed and continually updates a comprehensive environmental compliance strategy to assess compliance obligations associated with the current and proposed environmental requirements discussed above. As part of this strategy, the Company has developed a compliance plan for the MATS rule which includes 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, and the use of existing or additional natural gas capability. Additionally, certain transmission system upgrades may be required. SEGCO, jointly owned by the Company and Georgia Power, plans to add natural gas capability.

The impacts of the eight-hour ozone, fine particulate matter and SO_2 NAAQS, the Alabama opacity rule, CAIR and any future replacement rule, CAVR, the MATS rule, the NSPS for CTs, and the SSM rule on the Company cannot be determined at this time and will depend on the specific provisions of recently finalized and future rules, the resolution of pending and future legal challenges, and the development and implementation of rules at the state level. These regulations could result in significant additional 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. Further, higher costs that are recovered through regulated rates could contribute to reduced demand for electricity, which could negatively impact results of operations, cash flows, and financial condition.

Water Quality

In 2011, the EPA published a proposed rule that establishes standards for reducing effects on fish and other aquatic life caused by cooling water intake structures at existing power plants and manufacturing facilities. The rule also addresses cooling water intake structures for new units at existing facilities. Compliance with the proposed rule could require changes to existing cooling water intake structures at certain of the Company's generating facilities, and new generating units constructed at existing plants would be required to install closed cycle cooling towers. The EPA is required to issue a final rule by April 17, 2014.

On June 7, 2013, the EPA published a proposed rule which requested comments on a range of potential regulatory options for addressing certain wastestreams from steam electric power plants. These regulations could result in the installation of additional controls at certain of the facilities of the Company, which could result in significant capital expenditures and compliance costs that could affect future unit retirement and replacement decisions, depending on the specific technology requirements of the final rule. See FINANCIAL CONDITION AND LIQUIDITY – "Capital Requirements and Contractual Obligations" for additional information regarding estimated compliance costs for 2014 through 2016.

The impact of these proposed rules cannot be determined at this time and will depend on the specific provisions of the final rules and the outcome of any legal challenges. These 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. Further, higher costs that are recovered through regulated rates could contribute to reduced demand for electricity, which could negatively impact results of operations, cash flows, and financial condition.

Coal Combustion Residuals

The Company currently operates six electric generating plants with on-site coal combustion residuals storage facilities. In addition to on-site storage, the Company also sells a portion of its coal combustion residuals to third parties for beneficial reuse. Historically, individual states have regulated coal combustion residuals and the State of Alabama has its own regulatory requirements. The Company has a routine and robust inspection program in place to ensure the integrity of its coal ash surface impoundments and compliance with applicable regulations.

The EPA continues to evaluate the regulatory program for coal combustion residuals, including coal ash and gypsum, under federal solid and hazardous waste laws. In 2010, the EPA published a proposed rule that requested comments on two potential regulatory options for the management and disposal of coal combustion residuals: regulation as a solid waste or regulation as if the materials technically constituted a hazardous waste. Adoption of either option could require closure of, or significant change to, existing storage facilities and construction of lined landfills, as well as additional waste management and groundwater monitoring requirements. Under both options, the EPA proposes to exempt the beneficial reuse of coal combustion residuals from regulation; however, a hazardous or other designation indicative of heightened risk could limit or eliminate beneficial reuse options. Environmental groups and other parties have filed lawsuits in the U.S. District Court for the District of Columbia seeking to require the EPA to complete its rulemaking process and issue final regulations pertaining to the regulation of coal combustion residuals. On September 30, 2013, the U.S. District Court for the District of Columbia issued an order granting partial summary judgment to the environmental groups and other parties, ruling that the EPA has a statutory obligation to review and revise, as necessary, the federal solid waste regulations applicable to coal combustion residuals. On January 29, 2014, the EPA filed a consent decree requiring the EPA to take final action regarding the proposed regulation of coal combustion residuals as solid waste by December 19, 2014.

While the ultimate outcome of this matter cannot be determined at this time and will depend on the final form of any rules adopted and the outcome of any legal challenges, additional regulation of coal combustion residuals could have a material impact on the generation, management, beneficial use, and disposal of such residuals. Any material changes are likely to result in substantial additional compliance, operational, and capital costs that could affect future unit retirement and replacement decisions. Moreover, the Company could incur additional material asset retirement obligations with respect to closing existing storage facilities. The Company's results of operations, cash flows, and financial condition could be significantly impacted if such costs

MANAGEMENT'S DISCUSSION AND ANALYSIS (continued)
Alabama Power Company 2013 Annual Report

are not recovered through regulated rates. Further, higher costs that are recovered through regulated rates could contribute to reduced demand for electricity, which could negatively impact results of operations, cash flows, and financial condition. See FINANCIAL CONDITION AND LIQUIDITY – "Capital Requirements and Contractual Obligations" for additional information regarding estimated compliance costs for 2014 through 2016.

Global Climate Issues

The EPA currently regulates greenhouse gases under the Prevention of Significant Deterioration and Title V operating permit programs of the Clean Air Act. The legal basis for these regulations is currently being challenged in the U.S. Supreme Court. In addition, over the past several years, the U.S. Congress has considered many proposals to reduce greenhouse gas emissions, mandate renewable or clean energy, and impose energy efficiency standards. Such proposals are expected to continue to be considered by the U.S. Congress. International climate change negotiations under the United Nations Framework Convention on Climate Change are also continuing.

On January 8, 2014, the EPA published re-proposed regulations to establish standards of performance for greenhouse gas emissions from new fossil fuel steam electric generating units. A Presidential memorandum issued on June 25, 2013 also directs the EPA to propose standards, regulations, or guidelines for addressing modified, reconstructed, and existing steam electric generating units by June 1, 2014.

Although the outcome of any federal, state, and international initiatives, including the EPA's proposed regulations and guidelines discussed above, will depend on the scope and specific requirements of the proposed and final rules and the outcome of any legal challenges and, therefore, cannot be determined at this time, additional restrictions on the Company's greenhouse gas emissions or requirements relating to renewable energy or energy efficiency at the federal or state level could result in significant additional compliance costs, including capital expenditures. These costs could affect future unit retirement and replacement decisions and could result in the retirement of coal-fired generating units. Also, additional compliance costs and costs related to unit retirements could affect results of operations, cash flows, and financial condition if such costs are not recovered through regulated rates. Further, higher costs that are recovered through regulated rates could contribute to reduced demand for electricity, which could negatively impact results of operations, cash flows, and financial condition.

The EPA's greenhouse gas reporting rule requires annual reporting of carbon dioxide equivalent emissions in metric tons for a company's operational control of facilities. Based on ownership or financial control of facilities, the Company's 2012 greenhouse gas emissions were approximately 37 million metric tons of carbon dioxide equivalent. The preliminary estimate of the Company's 2013 greenhouse gas emissions on the same basis is approximately 41 million metric tons of carbon dioxide equivalent. The level of greenhouse gas emissions from year to year will depend on the level of generation and mix of fuel sources and other factors.

FERC Matters

In 2005, the Company filed two applications with the FERC for new 50-year licenses for the Company's seven hydroelectric developments on the Coosa River (Weiss, Henry, Logan Martin, Lay, Mitchell, Jordan, and Bouldin) and for the Lewis Smith and Bankhead developments on the Warrior River. The FERC licenses for all of these nine projects expired in 2007. Since the FERC did not act on the Company's new license applications prior to the expiration of the existing licenses, the FERC is required by law to issue annual licenses to the Company, under the terms and conditions of the existing license, until action is taken on the new license applications. The FERC issued annual licenses for the Coosa River developments and the Warrior River developments in 2007. These annual licenses are automatically renewed each year without further action by the FERC to allow the Company to continue operation of the projects under the terms of the previous license while the FERC completes review of the applications for new licenses. In 2010, the FERC issued a new 30-year license to the Company for the Warrior River developments. On March 18, 2013, following the FERC's denials of their requests for rehearing, the Smith Lake Improvement and Stakeholders' Association filed an appeal to the U.S. Court of Appeals for the District of Columbia Circuit regarding the FERC's orders related to the Warrior River relicensing proceedings.

On June 20, 2013, the FERC entered an order granting the Company's application for relicensing of the Company's seven hydroelectric developments on the Coosa River for 30 years. On July 22, 2013, the Company filed a petition requesting rehearing of the FERC order granting the relicense seeking revisions to several conditions of the license. The Alabama Rivers Alliance, American Rivers, the Georgia Environmental Protection Division, and the Atlanta Regional Commission have also filed petitions for rehearing of the FERC order.

In 2011, the Company filed an application with the FERC to relicense the Martin Dam Project. The current Martin license expired on June 8, 2013. Since the FERC did not act on the Company's licenses application prior to the expiration of the existing license, the FERC issued an annual license to the Company for the Martin Dam Project on June 18, 2013.

MANAGEMENT'S DISCUSSION AND ANALYSIS (continued)
Alabama Power Company 2013 Annual Report

On August 16, 2013, the Company filed an application with the FERC to relicense the Holt Hydroelectric Project. The current Holt license will expire on August 31, 2015.

Upon or after the expiration of each license, the U.S. Government, by act of Congress, may take over the project or the FERC may relicense the project either to the original licensee or to a new licensee. The FERC may grant relicenses subject to certain requirements that could result in additional costs to the Company. The timing and final outcome of the Company's relicense applications cannot be determined at this time.

PSC Matters

Retail Rate Adjustments

In 2011, the Alabama PSC issued an order to eliminate a tax-related adjustment under the Company's rate structure effective with October 2011 billings. The elimination of this adjustment resulted in additional revenues of approximately $31 million for 2011. In accordance with the order, the Company made additional accruals to the NDR in the fourth quarter 2011 of an amount equal to such additional 2011 revenues. The NDR was impacted as a result of operations and maintenance expenses incurred in connection with the 2011 storms in Alabama. See "Natural Disaster Reserve" below for additional information. The elimination of this adjustment resulted in additional revenues of approximately $106 million for 2012.

Rate RSE

Rate stabilization and equalization plan (Rate RSE) adjustments are based on forward-looking information for the applicable upcoming calendar year. Rate adjustments for any two-year period, when averaged together, cannot exceed 4.0% and any annual adjustment is limited to 5.0%. If the Company's actual retail return is above the allowed equity return range, customer refunds will be required; however, there is no provision for additional customer billings should the actual retail return fall below the allowed equity return range. Prior to 2014, retail rates remained unchanged when the retail return on common equity (ROE) was projected to be between 13.0% and 14.5%.

During 2013, the Alabama PSC held public proceedings regarding the operation and utilization of Rate RSE. On August 13, 2013 the Alabama PSC voted to issue a report on Rate RSE that found that the Company's Rate RSE mechanism continues to be just and reasonable to customers and the Company, but recommended the Company modify Rate RSE as follows:

- Eliminate the provision of Rate RSE establishing an allowed range of ROE.
- Eliminate the provision of Rate RSE limiting the Company's capital structure to an allowed equity ratio of 45%.
- Replace these two provisions with a provision that establishes rates based upon an allowed weighted cost of equity (WCE) range of 5.75% to 6.21%, with an adjusting point of 5.98%. If calculated under the previous Rate RSE provisions, the resulting WCE would range from 5.85% to 6.53%, with an adjusting point of 6.19%.
- Provide eligibility for a performance-based adder of seven basis points, or 0.07%, to the WCE adjusting point if the Company (i) has an "A" credit rating equivalent with at least one of the recognized rating agencies or (ii) is in the top one-third of a designated customer value benchmark survey.

Substantially all other provisions of Rate RSE were unchanged.

On August 21, 2013, the Company filed its consent to these recommendations with the Alabama PSC. The changes became effective for calendar year 2014. On November 27, 2013, the Company made its Rate RSE submission to the Alabama PSC of projected data for calendar year 2014; projected earnings were within the specified WCE range and, therefore, retail rates under Rate RSE remained unchanged for 2014. In 2012 and 2013, retail rates under Rate RSE remained unchanged from 2011. Under the terms of Rate RSE, the maximum possible increase for 2015 is 5.00%.

Rate CNP

The Company's retail rates, approved by the Alabama PSC, provide for adjustments to recognize the placing of new generating facilities into retail service under rate certificated new plant (Rate CNP). The Company may also recover retail costs associated with certificated PPAs under Rate CNP PPA. There was no adjustment to Rate CNP PPA in 2012. On March 5, 2013, the Alabama PSC issued a consent order that the Company leave in effect the current Rate CNP PPA factor for billings for the period April 1, 2013 through March 31, 2014. It is anticipated that no adjustment will be made to Rate CNP PPA in 2014. As of December 31, 2013, the Company had an under recovered certificated PPA balance of $18 million, all of which is included in deferred under recovered regulatory clause revenues in the balance sheet.

In 2011, the Alabama PSC approved and certificated a PPA of approximately 200 megawatts (MWs) of energy from wind-powered generating facilities which became operational in December 2012. In September 2012, the Alabama PSC approved and

MANAGEMENT'S DISCUSSION AND ANALYSIS (continued)
Alabama Power Company 2013 Annual Report

certificated a second wind PPA of approximately 200 MWs which became operational in January 2014. The terms of the wind PPAs permit the Company to use the energy and retire the associated environmental attributes in service of its customers or to sell environmental attributes, separately or bundled with energy. The Company has elected the normal purchase normal sale (NPNS) scope exception under the derivative accounting rules for its two wind PPAs, which total approximately 400 MWs. The NPNS exception allows the PPAs to be recorded at a cost, rather than fair value, basis. The industry's application of the NPNS exception to certain physical forward transactions in nodal markets is currently under review by the U.S. Securities and Exchange Commission (SEC) at the request of the electric utility industry. The outcome of the SEC's review cannot now be determined. If the Company is ultimately required to record these PPAs at fair value, an offsetting regulatory asset or regulatory liability will be recorded.
Rate CNP Environmental also allows for the recovery of the Company's retail costs associated with environmental laws, regulations, or other such mandates. Rate CNP Environmental is based on forward-looking information and provides for the recovery of these costs pursuant to a factor that is calculated annually. Environmental costs to be recovered include operations and maintenance expenses, depreciation, and a return on certain invested capital. There was no adjustment to Rate CNP Environmental in 2012 or 2013. On August 13, 2013, the Alabama PSC approved the Company's petition requesting a revision to Rate CNP Environmental that allows recovery of costs related to pre-2005 environmental assets previously being recovered through Rate RSE. The revenue impact as a result of this revision is estimated to be $58 million in 2014. On November 21, 2013, the Company submitted calculations associated with its cost of complying with environmental mandates, as provided under Rate CNP Environmental. The filing reflected a projected unrecovered retail revenue requirement for environmental compliance of approximately $72 million, which is to be recovered in the billing months of January 2014 through December 2014. On December 3, 2013, the Alabama PSC issued a consent order that the Company leave in effect for 2014 the factors associated with the Company's environmental compliance costs for the year 2013. Any unrecovered amounts associated with 2014 will be reflected in the 2015 filing. As of December 31, 2013, the Company had an under recovered environmental clause balance of $7 million which is included in deferred under recovered regulatory clause revenues in the balance sheet.

Environmental Accounting Order

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

Compliance and Pension Cost Accounting Order

In November 2012, the Alabama PSC approved an accounting order to defer to a regulatory asset account certain compliance-related operations and maintenance expenditures for the years 2013 through 2017, as well as the incremental increase in operations expense related to pension cost for 2013. These deferred costs are to be amortized over a three-year period beginning in January 2015. The compliance related expenditures were related to (i) standards addressing Critical Infrastructure Protection issued by the North American Electric Reliability Corporation, (ii) cyber security requirements issued by the U.S. Nuclear Regulatory Commission (NRC), and (iii) NRC guidance addressing the readiness at nuclear facilities within the U.S. for severe events. The compliance-related expenses to be afforded regulatory asset treatment over the five-year period are currently estimated to be approximately $37 million. The amount of operations and maintenance expenses deferred to a regulatory asset in 2013 associated with compliance-related expenditures and pension cost was approximately $8 million and $12 million, respectively. Pursuant to the accounting order, the Company has the ability to accelerate the amortization of the regulatory assets with notification to the Alabama PSC. See "Other Matters" herein for information regarding NRC actions as a result of the earthquake and tsunami that struck Japan in 2011.

Retail Energy Cost Recovery

The Company has established energy cost recovery rates under Rate ECR as approved by the Alabama PSC. Rates are based on an estimate of future energy costs and the current over or under recovered balance. Revenues recognized under Rate ECR and recorded on the financial statements are adjusted for the difference in actual recoverable fuel costs and amounts billed in current regulated rates. The difference in the recoverable fuel costs and amounts billed give rise to the over or under recovered amounts recorded as regulatory assets or liabilities. The Company, along with the Alabama PSC, continually monitors the over or under recovered cost balance to determine whether an adjustment to billing rates is required. Changes in the Rate ECR factor have no significant effect on the Company's net income, but will impact operating cash flows. Currently, the Alabama PSC may approve billing rates under Rate ECR of up to 5.910 cents per KWH. On December 3, 2013, the Alabama PSC issued a consent order that the Company leave in effect the energy cost recovery rates which began in April 2011 for 2014. Therefore, the Rate ECR factor as of January 1, 2014 remained at 2.681 cents per KWH. Effective with billings beginning in January 2015, the Rate ECR factor will be 5.910 cents per KWH, absent a further order from the Alabama PSC.

The Company's over recovered fuel costs at December 31, 2013 totaled $42 million as compared to under recovered fuel costs of $4 million at December 31, 2012. At December 31, 2013, $27 million is included in other regulatory liabilities, current and $15 million is included in deferred over recovered regulatory clause revenues. The under recovered fuel costs at December 31, 2012 are included in deferred under 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 of the under recovered fuel costs.

Natural Disaster Reserve

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

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.

In accordance with the order that was issued by the Alabama PSC in 2011 to eliminate a tax-related adjustment under the Company's rate structure that resulted in additional revenues, the Company made additional accruals to the NDR in the fourth quarter 2011 of an amount equal to the additional 2011 revenues, which were approximately $31 million. The accumulated balances in the NDR for the years ended December 31, 2013 and December 31, 2012 were approximately $96 million and $103 million, respectively. Any accruals to the NDR are included in the balance sheets under other regulatory liabilities, deferred and are reflected as other operations and maintenance expenses in the statements of income.

Nuclear Outage Accounting Order

In accordance with a 2010 Alabama PSC order, nuclear outage operations and maintenance expenses for the two units at Plant Farley are deferred to a regulatory asset when the charges actually occur and are then amortized over the subsequent 18-month operational cycle.

Approximately $31 million of nuclear outage costs from the spring of 2012 was amortized to nuclear operations and maintenance expenses over the 18-month period ended in December 2013. During the spring of 2013, approximately $28 million of nuclear outage costs was deferred to a regulatory asset, and beginning in July 2013, these deferred costs are being amortized over an 18-month period. During the fall of 2013, approximately $32 million of nuclear outage costs associated with the second unit was deferred to a regulatory asset, and beginning in January 2014, these deferred costs are being amortized over an 18-month period. The Company will continue the pattern of deferral of nuclear outage expenses as incurred and the recognition of expenses over a subsequent 18-month period pursuant to the Alabama PSC order.

Non-Nuclear Outage Accounting Order

On August 13, 2013, the Alabama PSC approved the Company's petition requesting authorization to defer to a regulatory asset account certain operations and maintenance expenses associated with planned outages at non-nuclear generation facilities in 2014 and to amortize those expenses over a three-year period beginning in 2015. The 2014 outage expenditures to be deferred and amortized are estimated to total approximately $78 million.

Income Tax Matters

Bonus Depreciation

On January 2, 2013, the American Taxpayer Relief Act of 2012 (ATRA) was signed into law. The ATRA retroactively extended several tax credits through 2013 and extended 50% bonus depreciation for property placed in service in 2013 (and for certain long-term production-period projects to be placed in service in 2014). The extension of 50% bonus depreciation had a positive impact on the Company's cash flows of approximately $74 million in 2013 and is expected to have a positive impact between $40 million and $45 million on the Company's 2014 cash flows.

Other Matters

In accordance with accounting standards related to employers' accounting for pensions, the Company recorded pension costs of $47 million in 2013 and $6 million in 2012 and recorded non-cash pre-tax pension income of $21 million in 2011. Postretirement benefit costs for the Company were $7 million, $10 million, and $11 million in 2013, 2012, and 2011, respectively. Such amounts are dependent on several factors including trust earnings and changes to the plans. A portion of pension and postretirement benefit costs is capitalized based on construction-related labor charges. Pension and postretirement benefit costs are a component of the regulated rates and generally do not have a long-term effect on net income. For more information regarding pension and postretirement benefits, see Note 2 to the financial statements.

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

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

In 2011, a major earthquake and tsunami struck Japan and caused substantial damage to the nuclear generating units at the Fukushima Daiichi generating plant. The events in Japan have created uncertainties that may affect future costs for operating nuclear plants. Specifically, the NRC is performing additional operational and safety reviews of nuclear facilities in the U.S., which could potentially impact future operations and capital requirements. In addition, the NRC has issued a series of orders requiring safety-related changes to U.S. nuclear facilities and expects to issue orders in the future requiring additional upgrades. The final form and the resulting impact of any changes to safety requirements for nuclear reactors will be dependent on further review and action by the NRC. See "PSC Matters – Compliance and Pension Cost Accounting Order" herein and Note 3 to the financial statements under "Retail Regulatory Matters – Compliance and Pension Cost Accounting Order" for additional information on the Company's PSC approved accounting order, which allows the deferral of certain compliance-related operations and maintenance expenditures related to compliance with the NRC guidance.

Additionally, there are certain risks associated with the operation of nuclear generating units, including potential impacts that could result from a major incident at a nuclear facility anywhere in the world. The ultimate outcome of these events cannot be determined at this time.

On November 19, 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. In accordance with the court's order, the DOE has submitted a proposal to the U.S. Congress to change the fee to zero. That proposal is pending before the U.S. Congress and will become effective after 90 days of legislative session from the time of submittal unless the U.S. Congress enacts legislation that impacts the proposed fee change. The DOE's petition for rehearing of the November 2013 decision is currently pending and the Company is continuing to pay the fee of approximately $13 million annually. The ultimate outcome of this matter cannot be determined at this time.

MANAGEMENT'S DISCUSSION AND ANALYSIS (continued)
Alabama Power Company 2013 Annual Report

ACCOUNTING POLICIES

Application of Critical Accounting Policies and Estimates

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

Electric Utility Regulation

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

Contingent Obligations

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

Pension and Other Postretirement Benefits

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

Key elements in determining the Company's pension and other postretirement benefit expense in accordance with GAAP 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 postretirement benefit plan assets is based on the Company's investment strategy, historical experience, and expectations for long-term rates of return that consider external actuarial advice. The Company determines the long-term return on plan assets by applying the long-term rate of expected returns on various asset classes to the Company's target asset allocation. The Company discounts the future cash flows related to its postretirement benefit plans using a single-point discount rate developed from the weighted average of market-observed yields for high quality fixed income securities with maturities that correspond to expected benefit payments.

A 25 basis point change in any significant assumption (discount rate, salaries, or long-term return on plan assets) would result in a $6 million or less change in total annual benefit expense and an $82 million or less change in projected obligations.

MANAGEMENT'S DISCUSSION AND ANALYSIS (continued)
Alabama Power Company 2013 Annual Report

FINANCIAL CONDITION AND LIQUIDITY
Overview
The Company's financial condition remained stable at December 31, 2013. The Company's cash requirements primarily consist of funding ongoing operations, common stock dividends, capital expenditures, and debt maturities. Capital expenditures and other investing activities include investments to comply with environmental regulations and for restoration following major storms. Operating cash flows provide a substantial portion of the Company's cash needs. For the three-year period from 2014 through 2016, the Company's projected common stock dividends, capital expenditures, and debt maturities are expected to exceed operating cash flows. Projected capital expenditures in that period include investments to maintain existing generation facilities, to add environmental equipment for existing generating units, and to expand and improve transmission and distribution facilities. The Company plans to finance future cash needs in excess of its operating cash flows primarily through debt and equity issuances. The Company intends to continue to monitor its access to short-term and long-term capital markets as well as its bank credit arrangements to meet future capital and liquidity needs. See "Sources of Capital," "Financing Activities," and "Capital Requirements and Contractual Obligations" herein for additional information.
The Company's investments in the qualified pension plan and the nuclear decommissioning trust funds increased in value as of December 31, 2013 as compared to December 31, 2012. No contributions to the qualified pension plan were made for the year ended December 31, 2013. The Company's funding obligations for the nuclear decommissioning trust fund are based on the site study, and the next study is expected to be conducted in 2018.
Net cash provided from operating activities totaled $1.9 billion for 2013, an increase of $538 million as compared to 2012. The increase in cash provided from operating activities was primarily due to changes in timing of fossil fuel stock purchases and payment of accounts payable, and collection of fuel cost recovery revenues. Net cash provided from operating activities totaled $1.4 billion for 2012, a decrease of $672 million as compared to 2011. The decrease in cash provided from operating activities was primarily due to an increase in fossil fuel stock, a decrease in deferred income taxes, and the timing of income tax payments and refunds associated with bonus depreciation.
Net cash used for investing activities totaled $1.1 billion for 2013, $0.9 billion for 2012, and $1.0 billion for 2011. In 2013, these additions were primarily due to gross property additions related to steam generation, distribution, and transmission equipment. In 2012, these additions were primarily due to gross property additions related to nuclear fuel and transmission, distribution, and steam generating equipment. In the prior years, gross property additions were primarily related to environmental mandates, construction of transmission and distribution facilities, replacement of steam generation equipment, and purchases of nuclear fuel.
Net cash used for financing activities totaled $614 million in 2013 primarily due to the payment of common stock dividends, and the issuance and a maturity of senior notes. Net cash used for financing activities totaled $649 million in 2012 primarily due to issuances, redemptions, and a maturity of senior notes, and payment of common stock dividends to Southern Company. Net cash used for financing activities totaled $869 million in 2011 primarily due to issuances, redemptions, and a maturity of debt securities and payment of higher common stock dividends. Fluctuations in cash flow from financing activities vary from year to year based on capital needs and the maturity or redemption of securities.
Significant balance sheet changes for 2013 include an increase of $620 million in property, plant, and equipment primarily due to additions to steam, distribution, and transmission facilities. Other significant changes include an increase of $276 million in prepaid pension costs and a decrease of $391 million in other regulatory assets, deferred, both of which are primarily attributable to a positive return on assets and an increase in the discount rate associated with retirement benefit plans.
The Company's ratio of common equity to total capitalization, including short-term debt, was 44.3% in 2013 and 44.0% in 2012. See Note 6 to the financial statements for additional information.
Sources of Capital

The Company plans to obtain the funds required for construction and other purposes from sources similar to those used in the past. The Company has primarily utilized funds from operating cash flows, short-term debt, security issuances, and equity contributions from Southern Company. However, the amount, type, and timing of any future financings, if needed, will depend upon prevailing market conditions, regulatory approval, and other factors. Security issuances are subject to regulatory approval by the Alabama PSC. Additionally, with respect to the public offering of securities, the Company files registration statements with the SEC under the Securities Act of 1933, as amended. The amounts of securities authorized by the Alabama PSC are continuously monitored and appropriate filings are made to ensure flexibility in the capital markets.

The Company obtains financing separately without credit support from any affiliate. See Note 6 to the financial statements under "Bank Credit Arrangements" for additional information. The Southern Company system does not maintain a centralized cash or money pool. Therefore, funds of the Company are not commingled with funds of any other company in the Southern Company system.

The Company's current liabilities sometimes exceed current assets because of the Company's debt due within one year and the periodic use of short-term debt as a funding source primarily to meet scheduled maturities of long-term debt, as well as cash needs, which can fluctuate significantly due to the seasonality of the business.

At December 31, 2013, the Company had approximately $295 million of cash and cash equivalents. Committed credit arrangements with banks at December 31, 2013 were as follows:

Expires[a]					Executable Term-Loans		Due Within One Year	
2014	2015	2018	Total	Unused	One Year	Two Years	Term Out	Not Term Out
			(in millions)					
$238	$35	$1,030	$1,303	$1,303	$53	$—	$53	$185

(a) No credit arrangements expire in 2016 or 2017.

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

Most of these arrangements contain covenants that limit debt levels and contain cross default provisions to other indebtedness (including guarantee obligations) of the Company. Such cross default provisions to other indebtedness would trigger an event of default if the Company defaulted on indebtedness or guarantee obligations over a specified threshold. The Company is currently in compliance with all such covenants. None of the arrangements contain material adverse change clauses at the time of borrowings. The Company expects to renew its credit arrangements as needed, prior to expiration.

In addition, the Company has substantial cash flow from operating activities and access to the capital markets, including a commercial paper program, to meet liquidity needs. A portion of the unused credit with banks is allocated to provide liquidity support to the Company's variable rate pollution control revenue bonds and commercial paper borrowings. As of December 31, 2013, the Company had $793 million of outstanding variable rate pollution control revenue bonds requiring liquidity support. In addition, at December 31, 2013, the Company had $200 million of fixed rate pollution control revenue bonds that will be required to be remarketed within the next 12 months.

The Company may meet short-term cash needs through its commercial paper program. The Company may also meet short-term cash needs through a Southern Company subsidiary organized to issue and sell commercial paper at the request and for the benefit of the Company and the other traditional operating companies. Proceeds from such issuances for the benefit of the Company are loaned directly to the Company. The obligations of each company under these arrangements are several and there is no cross-affiliate credit support.

Details of short-term borrowings were as follows:

	Short-term Debt at the End of the Period		Short-term Debt During the Period [a]		
	Amount Outstanding	Weighted Average Interest Rate	Average Outstanding	Weighted Average Interest Rate	Maximum Amount Outstanding
	(in millions)		(in millions)		(in millions)
December 31, 2013:					
Commercial paper	$—	—%	$11	0.2%	$90
December 31, 2012:					
Commercial paper	$—	—%	$6	0.2%	$57

December 31, 2011:					
Commercial paper	$—	—%	$20	0.2%	$255

(a) Average and maximum amounts are based upon daily balances during the twelve-month periods ended December 31, 2013, 2012, and 2011.

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

MANAGEMENT'S DISCUSSION AND ANALYSIS (continued)
Alabama Power Company 2013 Annual Report

Financing Activities

In November 2013, the Company's $250 million aggregate principal amount of its Series 2008B 5.80% Senior Notes due November 15, 2013 matured.

In December 2013, the Company issued $300 million aggregate principal amount of its Series 2013A 3.55% Senior Notes due December 1, 2023. The proceeds were used for general corporate purposes, including the Company's continuous construction program.

In addition to any financings that may be necessary to meet capital requirements and contractual obligations, the Company plans to continue, when economically feasible, a program to retire higher-cost securities and replace these obligations with lower-cost capital if market conditions permit.

Credit Rating Risk

The Company does not have any credit arrangements that would require material changes in payment schedules or terminations as a result of a credit rating downgrade. There are certain contracts that could require collateral, but not accelerated payment, in the event of a credit rating change to below BBB- and/or Baa3. These contracts are primarily for physical electricity purchases, fuel purchases, fuel transportation and storage, and energy price risk management. At December 31, 2013, the maximum potential collateral requirements under these contracts at a rating below BBB- and/or Baa3 were approximately $268 million. Included in these amounts are 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. Additionally, any credit rating downgrade could impact the Company's ability to access capital markets, particularly the short-term debt market and the variable rate pollution control revenue bond market.

On May 24, 2013, Standard and Poor's Rating Services, a division of the McGraw Hill Companies Inc. (S&P), revised the ratings outlook for Southern Company and the traditional operating companies, including the Company, from stable to negative.

On January 31, 2014, Moody's Investors Service, Inc. (Moody's) upgraded the senior unsecured debt and preferred stock ratings of the Company to A1 from A2 and A3 from Baa1, respectively. Moody's maintained the stable ratings outlook for the Company.

Market Price Risk

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

To mitigate future exposure to changes in interest rates, the Company enters into derivatives that have been designated as hedges. The weighted average interest rate on $984 million of long-term variable interest rate exposure that has not been hedged at January 1, 2014 was 0.72%. If the Company sustained a 100 basis point change in interest rates for all unhedged variable rate long-term debt, the change would affect annualized interest expense by approximately $10 million at January 1, 2014. See Note 1 to the financial statements under "Financial Instruments" and Note 11 to the financial statements for additional information.

To mitigate residual risks relative to movements in electricity prices, the Company enters into physical fixed-price contracts for the purchase and sale of electricity through the wholesale electricity market and, to a lesser extent, financial hedge contracts for natural gas purchases. The Company continues to manage a retail fuel-hedging program implemented per the guidelines of the Alabama PSC. The Company had no material change in market risk exposure for the year ended December 31, 2013 when compared to the December 31, 2012 reporting period.

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

Table of Contents Index to Financial Statements

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:

	2013 Changes	2012 Changes
	Fair Value	
	(in millions)	
Contracts outstanding at the beginning of the period, assets (liabilities), net	$(13)	$(48)
Contracts realized or settled	10	46
Current period changes[(a)]	2	(11)
Contracts outstanding at the end of the period, assets (liabilities), net	$(1)	$(13)

(a) 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:

	2013	2012
	mmBtu* Volume	
	(in millions)	
Commodity – Natural gas swaps	64	45
Commodity – Natural gas options	5	12
Total hedge volume	69	57

* million British thermal units (mmBtu)

The weighted average swap contract cost above market prices was approximately $0.02 per mmBtu as of December 31, 2013 and $0.30 per mmBtu as of December 31, 2012. 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 Company's retail energy cost recovery clause.

At December 31, 2013 and 2012, substantially all of the Company's energy-related derivative contracts were designated as regulatory hedges and are related to the Company's fuel-hedging program. Therefore, gains and losses are initially recorded as regulatory liabilities and assets, respectively, and then are included in fuel expense as they are recovered through the energy cost recovery clause. Certain other gains and losses on energy-related derivatives, designated as cash flow hedges, are initially deferred in other comprehensive income before being recognized in income in the same period as the hedged transaction. Gains and losses on energy-related derivative contracts that are not designated or fail to qualify as hedges are recognized in the statements of income as incurred and were not material for any year presented.

The Company uses over-the-counter contracts that are not exchange traded but are fair valued using prices which are market observable, and thus fall into Level 2. 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, 2013 were as follows:

		Fair Value Measurements December 31, 2013	
	Total	Maturity	
	Fair Value	Year 1	Years 2&3
	(in millions)		
Level 1	$—	$—	$—
Level 2	(1)	2	(3)
Level 3	—	—	—
Fair value of contracts outstanding at end of period	$(1)	$2	$(3)

The Company is exposed to market price risk in the event of nonperformance by counterparties to energy-related and interest rate derivative contracts. The Company only enters into agreements and material transactions with counterparties that have investment

MANAGEMENT'S DISCUSSION AND ANALYSIS (continued)
Alabama Power Company 2013 Annual Report

grade credit ratings by Moody's and S&P, or with counterparties who have posted collateral to cover potential credit exposure. Therefore, the Company does not anticipate market risk exposure from nonperformance by the counterparties. For additional information, see Note 1 to the financial statements under "Financial Instruments" and Note 11 to the financial statements.

Capital Requirements and Contractual Obligations

The Company's construction program consists of a base level capital investment and capital expenditures to comply with existing environmental statutes and regulations. Over the next three years, the Company estimates spending, as part of its base level capital investment, $575 million on Plant Farley (including nuclear fuel), $930 million on distribution facilities, and $654 million on transmission additions. These base level capital investment amounts also include capital expenditures related to contractual purchase commitments for nuclear fuel and capital expenditures covered under long-term service agreements. Proposed water and coal combustion residuals rules are not included in the construction program base level capital investment. The Company's base level construction program investments including investments to comply with existing environmental statutes and regulations and the estimated incremental compliance costs related to the proposed water and coal combustion residuals rules over the 2014 through 2016 three-year period, based on the assumption that coal combustion residuals will continue to be regulated as non-hazardous solid waste under the proposed rule, are estimated as follows:

	2014	2015	2016
Construction program:		(in millions)	
Base capital	$1,229	$1,210	$911
Existing environmental statutes and regulations	502	443	166
Total construction program base level capital investment	$1,731	$1,653	$1,077
Potential incremental environmental compliance investments:			
Proposed water and coal combustion residuals rules	$3	$9	$143

See FUTURE EARNINGS POTENTIAL – "Environmental Matters – Environmental Statutes and Regulations" for additional information.

The construction program is subject to periodic review and revision, and actual construction costs may vary from these estimates because of numerous factors. These factors include: changes in business conditions; changes in load projections; changes in environmental statutes and regulations; the outcome of any legal challenges to 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 the expected environmental compliance program; changes in FERC rules and regulations; Alabama PSC approvals; changes in legislation; the cost and efficiency of construction labor, equipment, and materials; project scope and design changes; storm impacts; and the cost of capital. In addition, there can be no assurance that costs related to capital expenditures will be fully recovered.

In addition to the funds required for the Company's construction program, approximately $654 million will be required by the end of 2016 for maturities of long-term debt. The Company plans to continue, when economically feasible, to retire higher cost securities and replace these obligations with lower cost capital if market conditions permit.

As a result of NRC requirements, the Company has external trust funds for nuclear decommissioning costs; however, the Company currently has no additional funding requirements. For additional information, see Note 1 to the financial statements under "Nuclear Decommissioning." The Company has also established an external trust fund for postretirement benefits as ordered by the Alabama PSC. The cumulative effect of funding these items over an extended period will diminish internally funded capital for other purposes and may require the Company to seek capital from other sources. See Note 2 to the financial statements for additional information.

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

Table of Contents Index to Financial Statements

MANAGEMENT'S DISCUSSION AND ANALYSIS (continued)
Alabama Power Company 2013 Annual Report

Contractual Obligations

	2014	2015-2016	2017-2018	After 2018	Total
	(in millions)				
Long-term debt[(a)] —					
Principal	$—	$654	$561	$5,018	$6,233
Interest	243	484	431	3,225	4,383
Preferred and preference stock dividends[(b)]	39	79	79	—	197
Financial derivative obligations[(c)]	3	5	—	—	8
Operating leases[(d)]	15	24	10	15	64
Capital Lease	—	1	1	3	5
Purchase commitments —					
Capital[(e)]	1,590	2,563	—	—	4,153
Fuel[(f)]	1,351	1,787	854	804	4,796
Purchased power[(g)]	58	121	128	570	877
Other[(h)]	45	63	45	14	167
Pension and other postretirement benefit plans[(i)]	17	33	—	—	50
Total	$3,361	$5,814	$2,109	$9,649	$20,933

(a) All amounts are reflected based on final maturity dates. The Company plans to continue 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, 2014, as reflected in the statements of capitalization. Fixed rates include, where applicable, the effects of interest rate derivatives employed to manage interest rate risk.

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

(c) For additional information, see Notes 1 and 11 to the financial statements.

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

(e) The Company provides estimated capital expenditures for a three-year period, including capital expenditures and compliance costs associated with existing environmental regulations. Such amounts exclude the Company's estimates of potential incremental environmental compliance investment to comply with proposed water and coal combustion residuals rules, which are approximately $3 million, $9 million, and $143 million for 2014, 2015, and 2016, respectively. These amounts also exclude contractual purchase commitments for nuclear fuel and capital expenditures covered under long-term service agreements, which are reflected separately. At December 31, 2013, significant purchase commitments were outstanding in connection with the construction program. See FUTURE EARNINGS POTENTIAL – "Environmental Matters – Environmental Statutes and Regulations" for additional information.

(f) Includes commitments to purchase coal, 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, 2013.

(g) Estimated minimum long-term obligations for various long-term commitments for the purchase of capacity and energy. Amounts are related to the Company's certificated PPAs which include MWs purchased from gas-fired and wind-powered facilities.

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

(i) The Company forecasts contributions to the pension and other postretirement benefit plans over a three-year period. The Company anticipates no mandatory contributions to the qualified pension plan during the next three years.

Amounts presented represent estimated benefit payments for the nonqualified pension plans, estimated non-trust benefit payments for the other postretirement benefit plans, and estimated contributions to the other postretirement benefit plan trusts, all of which will be made from the Company's corporate assets. See Note 2 to the financial statements for additional information related to the pension and other postretirement benefit plans, including estimated benefit payments. Certain benefit payments will be made through the related benefit plans. Other benefit payments will be made from the Company's corporate assets.

Table of Contents Index to Financial Statements

MANAGEMENT'S DISCUSSION AND ANALYSIS (continued)
Alabama Power Company 2013 Annual Report

Cautionary Statement Regarding Forward Looking Statements

The Company's 2013 Annual Report contains forward-looking statements. Forward-looking statements include, among other things, statements concerning retail sales, retail rates, customer growth, economic recovery, fuel and environmental cost recovery and other rate actions, current and proposed environmental regulations and related estimated expenditures, access to sources of capital, projections for the qualified pension plan, postretirement benefit plan, and nuclear decommissioning trust fund contributions, financing activities, filings with state and federal regulatory authorities, impact of the ATRA, estimated sales and purchases under new power sale and purchase agreements, and estimated construction and other 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 including regulation of water, coal combustion residuals, and emissions of sulfur, nitrogen, carbon, soot, particulate matter, hazardous air pollutants, including mercury, and other substances, and also changes in tax and other laws and regulations to which the Company is subject, as well as changes in application of existing laws and regulations;
- current and future litigation, regulatory investigations, proceedings, or inquiries, including FERC matters, pending EPA civil action against the Company, and Internal Revenue Service and state tax audits;
- the effects, extent, and timing of the entry of additional competition in the markets in which the Company operates;
- variations in demand for electricity, including those relating to weather, the general economy and recovery from the recent recession, population and business growth (and declines), the effects of energy conservation 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;
- ability to control costs and avoid cost overruns during the development and construction of facilities, to construct facilities in accordance with the requirements of permits and licenses, and to satisfy any operational and environmental performance standards;
- investment performance of the Company's employee and retiree benefit plans and nuclear decommissioning trust funds;
- advances in technology;
- state and federal rate regulations and the impact of pending and future rate cases and negotiations, including rate actions relating to fuel and other cost recovery mechanisms;
- the inherent risks involved in operating nuclear generating facilities, including environmental, health, regulatory, natural disaster, terrorism, or financial risks;
- internal restructuring or other restructuring options that may be pursued;
- potential business strategies, including acquisitions or dispositions of assets or businesses, which cannot be assured to be completed or beneficial to the Company;
- the ability of counterparties of the Company to make payments as and when due and to perform as required;
- the ability to obtain new short- and long-term contracts with wholesale customers;
- the direct or indirect effect on the Company's business resulting from terrorist incidents and the threat of terrorist incidents, including cyber intrusion;
- interest rate fluctuations and financial market conditions and the results of financing efforts, including the Company's credit ratings;

- the impacts of any potential U.S. credit rating downgrade or other sovereign financial issues, including impacts on interest rates, access to capital markets, impacts on currency exchange rates, counterparty performance, and the economy in general;
- the ability of the Company to obtain additional generating capacity at competitive prices;
- catastrophic events such as fires, earthquakes, explosions, floods, tornadoes, hurricanes, droughts, pandemic health events such as influenzas, or other similar occurrences;

Table of Contents Index to Financial Statements

- the direct or indirect effects on the Company's business resulting from incidents affecting the U.S. electric grid or operation of generating resources;
- the effect of accounting pronouncements issued periodically by standard setting bodies; and
- other factors discussed elsewhere herein and in other reports (including the Form 10-K) filed by the Company from time to time with the SEC.

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

Table of Contents Index to Financial Statements

STATEMENTS OF INCOME
For the Years Ended December 31, 2013, 2012, and 2011
Alabama Power Company 2013 Annual Report

	2013	2012	2011
	(in millions)		
Operating Revenues:			
Retail revenues	$4,952	$4,933	$4,972
Wholesale revenues, non-affiliates	248	277	287
Wholesale revenues, affiliates	212	111	244
Other revenues	206	199	199
Total operating revenues	5,618	5,520	5,702
Operating Expenses:			
Fuel	1,631	1,503	1,679
Purchased power, non-affiliates	100	73	73
Purchased power, affiliates	129	182	198
Other operations and maintenance	1,289	1,287	1,262
Depreciation and amortization	645	639	637
Taxes other than income taxes	348	340	339
Total operating expenses	4,142	4,024	4,188
Operating Income	1,476	1,496	1,514
Other Income and (Expense):			
Allowance for equity funds used during construction	32	19	22
Interest income	16	16	18
Interest expense, net of amounts capitalized	(259)	(287)	(299)
Other income (expense), net	(36)	(24)	(30)
Total other income and (expense)	(247)	(276)	(289)
Earnings Before Income Taxes	1,229	1,220	1,225
Income taxes	478	477	478
Net Income	751	743	747
Dividends on Preferred and Preference Stock	39	39	39
Net Income After Dividends on Preferred and Preference Stock	$712	$704	$708

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

Table of Contents Index to Financial Statements

STATEMENTS OF COMPREHENSIVE INCOME
For the Years Ended December 31, 2013, 2012, and 2011
Alabama Power Company 2013 Annual Report

	2013	2012	2011
	(in millions)		
Net Income	$751	$743	$747
Other comprehensive income (loss):			
Qualifying hedges:			
Changes in fair value, net of tax of $-, $(7), and $(5), respectively	—	(11)	(9)
Reclassification adjustment for amounts included in net income, net of tax of $1, $1, and $(1), respectively	1	2	(2)
Total other comprehensive income (loss)	1	(9)	(11)
Comprehensive Income	$752	$734	$736

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

Table of Contents Index to Financial Statements

STATEMENTS OF CASH FLOWS
For the Years Ended December 31, 2013, 2012, and 2011
Alabama Power Company 2013 Annual Report

	2013	2012	2011
	(in millions)		
Operating Activities:			
Net income	$751	$743	$747
Adjustments to reconcile net income to net cash provided from operating activities —			
Depreciation and amortization, total	816	767	749
Deferred income taxes	198	164	459
Allowance for equity funds used during construction	(32)	(19)	(22)
Pension, postretirement, and other employee benefits	9	(21)	(41)
Stock based compensation expense	10	9	6
Natural disaster reserve	3	3	34
Other, net	(41)	(27)	(41)
Changes in certain current assets and liabilities —			
-Receivables	2	23	18
-Fossil fuel stock	146	(132)	47
-Materials and supplies	19	(21)	(33)
-Other current assets	5	(4)	(6)
-Accounts payable	35	(77)	11
-Accrued taxes	(23)	(12)	157
-Accrued compensation	(23)	(3)	(12)
-Retail fuel cost over recovery	42	1	—
-Other current liabilities	(3)	(18)	(25)
Net cash provided from operating activities	1,914	1,376	2,048
Investing Activities:			
Property additions	(1,107)	(867)	(977)
Investment in restricted cash from pollution control bonds	—	1	4
Distribution of restricted cash from pollution control bonds	—	—	13
Nuclear decommissioning trust fund purchases	(280)	(194)	(350)
Nuclear decommissioning trust fund sales	279	193	349
Cost of removal net of salvage	(47)	(33)	(28)
Change in construction payables	(13)	12	(9)
Other investing activities	26	(46)	9
Net cash used for investing activities	(1,142)	(934)	(989)
Financing Activities:			
Proceeds —			
Capital contributions from parent company	24	27	12
Senior notes issuances	300	1,000	700
Redemptions —			
Pollution control revenue bonds	—	(1)	(4)
Senior notes	(250)	(950)	(750)
Payment of preferred and preference stock dividends	(39)	(39)	(39)
Payment of common stock dividends	(644)	(684)	(774)
Other financing activities	(5)	(2)	(14)
Net cash used for financing activities	(614)	(649)	(869)

Net Change in Cash and Cash Equivalents	158	(207)	190
Cash and Cash Equivalents at Beginning of Year	137	344	154
Cash and Cash Equivalents at End of Year	$295	$137	$344
Supplemental Cash Flow Information:			
Cash paid during the period for —			
Interest (net of $11, $7 and $9 capitalized, respectively)	$243	$273	$286
Income taxes (net of refunds)	296	309	(139)
Noncash transactions - accrued property additions at year-end	18	31	19

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

Table of Contents Index to Financial Statements

BALANCE SHEETS
At December 31, 2013 and 2012
Alabama Power Company 2013 Annual Report

Assets	2013 (in millions)	2012
Current Assets:		
Cash and cash equivalents	$295	$137
Receivables —		
Customer accounts receivable	341	321
Unbilled revenues	142	138
Under recovered regulatory clause revenues	—	23
Other accounts and notes receivable	30	42
Affiliated companies	54	55
Accumulated provision for uncollectible accounts	(8)	(8)
Fossil fuel stock, at average cost	329	475
Materials and supplies, at average cost	375	395
Vacation pay	63	61
Prepaid expenses	57	81
Other regulatory assets, current	7	24
Other current assets	6	13
Total current assets	1,691	1,757
Property, Plant, and Equipment:		
In service	22,092	21,407
Less accumulated provision for depreciation	8,114	7,761
Plant in service, net of depreciation	13,978	13,646
Nuclear fuel, at amortized cost	332	354
Construction work in progress	748	438
Total property, plant, and equipment	15,058	14,438
Other Property and Investments:		
Equity investments in unconsolidated subsidiaries	54	53
Nuclear decommissioning trusts, at fair value	714	605
Miscellaneous property and investments	80	78
Total other property and investments	848	736
Deferred Charges and Other Assets:		
Deferred charges related to income taxes	519	525
Prepaid pension costs	276	—
Deferred under recovered regulatory clause revenues	25	11
Other regulatory assets, deferred	692	1,083
Other deferred charges and assets	142	162
Total deferred charges and other assets	1,654	1,781
Total Assets	$19,251	$18,712

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

Table of Contents Index to Financial Statements

BALANCE SHEETS
At December 31, 2013 and 2012
Alabama Power Company 2013 Annual Report

Liabilities and Stockholder's Equity	2013 (in millions)	2012
Current Liabilities:		
Securities due within one year	$—	$250
Accounts payable —		
Affiliated	198	191
Other	339	318
Customer deposits	85	85
Accrued taxes —		
Accrued income taxes	11	5
Other accrued taxes	33	33
Accrued interest	61	62
Accrued vacation pay	53	50
Accrued compensation	74	94
Other regulatory liabilities, current	37	3
Other current liabilities	41	52
Total current liabilities	932	1,143
Long-Term Debt (See accompanying statements)	6,233	5,929
Deferred Credits and Other Liabilities:		
Accumulated deferred income taxes	3,603	3,404
Deferred credits related to income taxes	75	79
Accumulated deferred investment tax credits	133	141
Employee benefit obligations	195	321
Asset retirement obligations	730	589
Other cost of removal obligations	828	759
Other regulatory liabilities, deferred	259	183
Deferred over recovered regulatory clause revenues	15	—
Other deferred credits and liabilities	61	81
Total deferred credits and other liabilities	5,899	5,557
Total Liabilities	13,064	12,629
Redeemable Preferred Stock (See accompanying statements)	342	342
Preference Stock (See accompanying statements)	343	343
Common Stockholder's Equity (See accompanying statements)	5,502	5,398
Total Liabilities and Stockholder's Equity	$19,251	$18,712
Commitments and Contingent Matters (See notes)		

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

Table of Contents Index to Financial Statements

STATEMENTS OF CAPITALIZATION
At December 31, 2013 and 2012
Alabama Power Company 2013 Annual Report

	2013	2012	2013	2012
	(in millions)		(percent of total)	
Long-Term Debt:				
Long-term debt payable to affiliated trusts —				
Variable rate (3.35% at 1/1/14) due 2042	$206	$206		
Long-term notes payable —				
5.80% due 2013	—	250		
0.55% due 2015	400	400		
5.20% due 2016	200	200		
5.50% to 5.55% due 2017	525	525		
3.375% to 6.125% due 2019-2042	3,750	3,450		
Total long-term notes payable	4,875	4,825		
Other long-term debt —				
Pollution control revenue bonds —				
0.40% to 5.00% due 2034	367	367		
Variable rate (0.04% at 1/1/14) due 2015	54	54		
Variable rates (0.09% to 0.10% at 1/1/14) due 2017	36	36		
Variable rates (0.02% to 0.13% at 1/1/14) due 2021-2038	694	694		
Total other long-term debt	1,151	1,151		
Capitalized lease obligations	5	—		
Unamortized debt premium (discount), net	(4)	(3)		
Total long-term debt (annual interest requirement — $243 million)	6,233	6,179		
Less amount due within one year	—	250		
Long-term debt excluding amount due within one year	6,233	5,929	50.2%	49.4%

STATEMENTS OF CAPITALIZATION (continued)
At December 31, 2013 and 2012
Alabama Power Company 2013 Annual Report

	2013	2012	2013	2012
	(in millions)		(percent of total)	
Redeemable Preferred Stock:				
Cumulative redeemable preferred stock				
$100 par or stated value — 4.20% to 4.92%				
Authorized — 3,850,000 shares				
Outstanding — 475,115 shares	48	48		
$1 par value — 5.20% to 5.83%				
Authorized — 27,500,000 shares				
Outstanding — 12,000,000 shares: $25 stated value				
(annual dividend requirement — $18 million)	294	294		
Total redeemable preferred stock	342	342	2.7	2.8
Preference Stock:				
Authorized — 40,000,000 shares				
Outstanding — $1 par value — 5.63% to 6.50%				
— 14,000,000 shares				
(non-cumulative) $25 stated value				
(annual dividend requirement — $21 million)	343	343	2.8	2.9
Common Stockholder's Equity:				
Common stock, par value $40 per share —				
Authorized: 40,000,000 shares				
Outstanding: 30,537,500 shares	1,222	1,222		
Paid-in capital	2,262	2,227		
Retained earnings	2,044	1,976		
Accumulated other comprehensive income (loss)	(26)	(27)		
Total common stockholder's equity	5,502	5,398	44.3	44.9
Total Capitalization	$12,420	$12,012	100.0 %	100.0 %

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

STATEMENTS OF COMMON STOCKHOLDER'S EQUITY
For the Years Ended December 31, 2013, 2012, and 2011
Alabama Power Company 2013 Annual Report

	Number of Common Shares Issued (in millions)	Common Stock	Paid-In Capital	Retained Earnings	Accumulated Other Comprehensive Income (Loss)	Total
Balance at December 31, 2010	31	$1,222	$2,156	$2,022	$(7)	$5,393
Net income after dividends on preferred and preference stock	—	—	—	708	—	708
Capital contributions from parent company	—	—	26	—	—	26
Other comprehensive income (loss)	—	—	—	—	(11)	(11)
Cash dividends on common stock	—	—	—	(774)	—	(774)
Balance at December 31, 2011	31	1,222	2,182	1,956	(18)	5,342
Net income after dividends on preferred and preference stock	—	—	—	704	—	704
Capital contributions from parent company	—	—	45	—	—	45
Other comprehensive income (loss)	—	—	—	—	(9)	(9)
Cash dividends on common stock	—	—	—	(684)	—	(684)
Balance at December 31, 2012	31	1,222	2,227	1,976	(27)	5,398
Net income after dividends on preferred and preference stock	—	—	—	712	—	712
Capital contributions from parent company	—	—	35	—	—	35
Other comprehensive income (loss)	—	—	—	—	1	1
Cash dividends on common stock	—	—	—	(644)	—	(644)
Balance at December 31, 2013	31	$1,222	$2,262	$2,044	$(26)	$5,502

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

Table of Contents Index to Financial Statements

NOTES TO FINANCIAL STATEMENTS
Alabama Power Company 2013 Annual Report

Index to the Notes to Financial Statements

NOTES (continued)
Alabama Power Company 2013 Annual Report

1. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES
General
Alabama Power Company (the Company) is a wholly owned subsidiary of The Southern Company (Southern Company), which is the parent company of four traditional operating companies, Southern Power Company (Southern Power), Southern Company Services, Inc. (SCS), Southern Communications Services, Inc. (SouthernLINC Wireless), Southern Company Holdings, Inc. (Southern Holdings), Southern Nuclear Operating Company, Inc. (Southern Nuclear), and other direct and indirect subsidiaries. The traditional operating companies – the Company, Georgia Power Company (Georgia Power), Gulf Power Company (Gulf Power), and Mississippi Power Company (Mississippi Power) – are vertically integrated utilities providing electric service in four Southeastern states. The Company operates as a vertically integrated utility providing electricity to retail and wholesale customers within its traditional service territory located in the State of Alabama in addition to wholesale customers in the Southeast. Southern Power constructs, acquires, owns, and manages generation assets, including renewable energy projects, and sells electricity at market-based rates in the wholesale market. 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. Southern Nuclear operates and provides services to the Southern Company system's nuclear power plants, including the Company's Plant Farley.
The equity method is used for subsidiaries in which the Company has significant influence but does not control and for variable interest entities (VIEs) where the Company has an equity investment, but is not the primary beneficiary.
The Company is subject to regulation by the Federal Energy Regulatory Commission (FERC) and the Alabama Public Service Commission (PSC). The Company follows generally accepted accounting principles (GAAP) in the U.S. and complies with the accounting policies and practices prescribed by its regulatory commissions. The preparation of financial statements in conformity with GAAP requires the use of estimates, and the actual results may differ from those estimates. Certain prior years' data presented in the financial statements have been reclassified to conform to the current year presentation.
Affiliate Transactions
The Company has an agreement with SCS under which the following services are rendered to the Company at direct or allocated cost: general and design engineering, operations, purchasing, accounting, finance and treasury, tax, information technology, marketing, auditing, insurance and pension administration, human resources, systems and procedures, digital wireless communications, and other services with respect to business and operations, construction management, and power pool transactions. Costs for these services amounted to $340 million, $340 million, and $347 million during 2013, 2012, and 2011, respectively. Cost allocation methodologies used by SCS prior to the repeal of the Public Utility Holding Company Act of 1935, as amended, were approved by the U.S. Securities and Exchange Commission (SEC). Subsequently, additional cost allocation methodologies have been reported to the FERC and management believes they are reasonable. The FERC permits services to be rendered at cost by system service companies.
The Company has an agreement with Southern Nuclear under which the following nuclear-related services are rendered to the Company at cost: general executive and advisory services, general operations, management and technical services, administrative services including procurement, accounting, employee relations, systems and procedures services, strategic planning and budgeting services, and other services with respect to business and operations. Costs for these services amounted to $211 million, $218 million, and $215 million during 2013, 2012, and 2011, respectively.
The Company jointly owns Plant Greene County with Mississippi Power. The Company has an agreement with Mississippi Power under which the Company operates Plant Greene County, and Mississippi Power reimburses the Company for its proportionate share of non-fuel expenses, which were $13 million in 2013, $12 million in 2012, and

$12 million in 2011. Also, Mississippi Power reimburses the Company for any direct fuel purchases delivered from one of the Company's transfer facilities, which were $27 million in 2013, $28 million in 2012, and $21 million in 2011. See Note 4 for additional information.

The Company has an agreement with Gulf Power under which the Company will make transmission system upgrades to ensure firm delivery of energy under a non-affiliate PPA. In 2009, Gulf Power entered into a PPA for the capacity and energy from a combined cycle plant located in Autauga County, Alabama. The total cost committed by the Company related to the upgrades is approximately $22 million in 2013 and $31 million in 2014. The Company expects to recover a majority of these costs through a tariff with Gulf Power until 2023. The remainder of these costs will be recovered through normal rate mechanisms.

NOTES (continued)
Alabama Power Company 2013 Annual Report

The Company provides incidental services to and receives such services from other Southern Company subsidiaries which are generally minor in duration and amount. Except as described herein, the Company neither provided nor received any material services to or from affiliates in 2013, 2012, or 2011.

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

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

NOTES (continued)
Alabama Power Company 2013 Annual Report

Regulatory Assets and Liabilities

The Company is subject to the provisions of the Financial Accounting Standards Board 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:

	2013	2012	Note
	(in millions)		
Deferred income tax charges	$519	$525	(a,k)
Loss on reacquired debt	86	93	(b)
Vacation pay	63	61	(c,j)
Under/(over) recovered regulatory clause revenues	(18)	34	(d)
Fuel-hedging (realized and unrealized) losses	8	18	(e)
Other regulatory assets	52	51	(f)
Asset retirement obligations	(132)	(64)	(a)
Other cost of removal obligations	(828)	(759)	(a)
Deferred income tax credits	(75)	(79)	(a)
Fuel-hedging (realized and unrealized) gains	(8)	(5)	(e)
Nuclear outage	51	33	(d)
Natural disaster reserve	(96)	(103)	(h)
Other regulatory liabilities	(11)	(13)	(d,g)
Retiree benefit plans	461	911	(i,j)
Regulatory deferrals	20	—	(l)
Total regulatory assets (liabilities), net	$92	$703	

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

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

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

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

(d) Recorded and recovered or amortized as approved or accepted by the Alabama PSC over periods not exceeding ten years.

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

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

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

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

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

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

(k) Included in the deferred income tax charges are $20 million for 2013 and $21 million for 2012 for the retiree Medicare drug subsidy, which is recovered and amortized, as approved by the Alabama PSC, over the average remaining service period which may range up to 15 years.

(l) Recorded and amortized as approved by the Alabama PSC for 2015 through 2017.

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

NOTES (continued)
Alabama Power Company 2013 Annual Report

Revenues
Wholesale capacity revenues are generally recognized on a levelized basis over the appropriate contract period. Energy and other revenues are recognized as services are provided. Unbilled revenues related to retail sales are accrued at the end of each fiscal period. Electric rates for the Company include provisions to adjust billings for fluctuations in fuel costs, fuel hedging, the energy component of purchased power costs, and certain other costs. Revenues are adjusted for differences between these actual costs and amounts billed in current regulated rates. Under or over recovered regulatory clause revenues are recorded in the balance sheets and are recovered or returned to customers through adjustments to the billing factors. The Company continuously monitors the under/over recovered balances and files for revised rates as required or when management deems appropriate, depending on the rate. See Note 3 under "Retail Regulatory Matters – Energy Cost Recovery" and "Retail Regulatory Matters – Rate CNP" for additional information.
The Company has a diversified base of customers. No single customer or industry comprises 10% or more of revenues. For all periods presented, uncollectible accounts averaged less than 1% of revenues.
Fuel Costs
Fuel costs are expensed as the fuel is used. Fuel expense generally includes fuel transportation costs and the cost of purchased emissions allowances as they are used. Fuel expense also includes the amortization of the cost of nuclear fuel and a charge, based on nuclear generation, for the permanent disposal of spent nuclear fuel. See Note 3 under "Nuclear Fuel Disposal Costs" for additional information.
Income and Other Taxes
The Company uses the liability method of accounting for deferred income taxes and provides deferred income taxes for all significant income tax temporary differences. Investment tax credits (ITCs) utilized are deferred and amortized to income over the average life of the related property. Taxes that are collected from customers on behalf of governmental agencies to be remitted to these agencies are presented net on the statements of income.
In accordance with accounting standards related to the uncertainty in income taxes, the Company recognizes tax positions that are "more likely than not" of being sustained upon examination by the appropriate taxing authorities. See Note 5 under "Unrecognized Tax Benefits" for additional information.
Property, Plant, and Equipment
Property, plant, and equipment is stated at original cost less any regulatory disallowances and impairments. Original cost includes: materials; labor; minor items of property; appropriate administrative and general costs; payroll-related costs such as taxes, pensions, and other benefits; and the interest capitalized and cost of equity funds used during construction.
The Company's property, plant, and equipment in service consisted of the following at December 31:

	2013	2012
	(in millions)	
Generation	$11,314	$11,110
Transmission	3,287	3,137
Distribution	5,934	5,714
General	1,545	1,434
Plant acquisition adjustment	12	12
Total plant in service	$22,092	$21,407

The cost of replacements of property, exclusive of minor items of property, is capitalized. The cost of maintenance, repairs, and replacement of minor items of property is charged to other operations and maintenance expenses as incurred or performed with the exception of nuclear refueling costs, which are recorded in accordance with specific Alabama PSC orders.
In 2010, the Alabama PSC approved the Company's request to stop accruing for nuclear refueling outage costs in advance of the refueling outages when the most recent 18-month amortization cycle ended in December 2010 and to

begin deferring nuclear outage expenses. The amortization will begin after each outage has occurred and the associated outage expenses are known.

During 2011, the Company deferred $38 million of nuclear outage expenses associated with the fall 2011 outage and began the first 18-month amortization cycle for expenses in January 2012. These expenses were fully amortized in June 2013. The

II-156

NOTES (continued)
Alabama Power Company 2013 Annual Report

Company deferred an additional $31 million of nuclear outage expenses associated with the spring 2012 outage and began the second amortization cycle in July 2012. These expenses were fully amortized in December 2013.

During 2013, the Company deferred $28 million of nuclear outage expenses associated with the spring 2013 outage and began the 18-month amortization cycle for expenses in July 2013. The Company deferred an additional $32 million of nuclear outage expenses associated with the fall 2013 outage and began the 18-month amortization cycle for expenses in January 2014.

The total unamortized deferred nuclear outage expense balance of $51 million is included in the 2013 balance sheet as a regulatory asset.

Depreciation and Amortization

Depreciation of the original cost of utility plant in service is provided primarily by using composite straight-line rates, which approximated 3.2% in 2013 and 2012, and 3.3% in 2011. Depreciation studies are conducted periodically to update the composite rates and the information is provided to the Alabama PSC and the FERC. When property subject to composite depreciation is retired or otherwise disposed of in the normal course of business, its original cost, together with the cost of removal, less salvage, is charged to accumulated depreciation. For other property dispositions, the applicable cost and accumulated depreciation are removed from the balance sheet accounts, and a gain or loss is recognized. Minor items of property included in the original cost of the plant are retired when the related property unit is retired.

In 2011, the Company submitted a depreciation study to the FERC and received authorization to use the recommended rates beginning January 2012. The study was also provided to the Alabama PSC.

Asset Retirement Obligations and Other Costs of Removal

Asset retirement obligations are computed as the present value of the 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. The Company has received accounting guidance from the Alabama PSC allowing the continued accrual of other future retirement costs for long-lived assets that the Company does not have a legal obligation to retire. Accordingly, the accumulated removal costs for these obligations are reflected in the balance sheets as a regulatory liability.

The liability for asset retirement obligations primarily relates to the decommissioning of the Company's nuclear facility, Plant Farley. In addition, the Company has retirement obligations related to various landfill sites, underground storage tanks, asbestos removal, and disposal of polychlorinated biphenyls in certain transformers. The Company also has identified retirement obligations related to certain transmission and distribution facilities and certain wireless communication towers. However, liabilities for the removal of these assets have not been recorded because the settlement timing for the retirement obligations related to these assets are indeterminable and, therefore, the fair value of the retirement obligations cannot be reasonably estimated. A liability for these asset retirement obligations will be recognized when sufficient information becomes available to support a reasonable estimation of the asset retirement obligation. The Company will continue to recognize in the statements of income allowed removal costs in accordance with its regulatory treatment. Any differences between costs recognized in accordance with accounting standards related to asset retirement and environmental obligations and those reflected in rates are recognized as either a regulatory asset or liability, as ordered by the Alabama PSC, and are reflected in the balance sheets. See "Nuclear Decommissioning" herein for additional information on amounts included in rates.

Details of the asset retirement obligations included in the balance sheets are as follows:

	2013	2012
	(in millions)	
Balance at beginning of year	$589	$553
Liabilities incurred	—	—
Liabilities settled	(1)	(1)
Accretion	40	37

Cash flow revisions [a]	102	—
Balance at end of year	$730	$589

(a) Updated based on results from the 2013 nuclear decommissioning study

NOTES (continued)
Alabama Power Company 2013 Annual Report

Nuclear Decommissioning
The U.S. Nuclear Regulatory Commission (NRC) requires licensees of commercial nuclear power reactors to establish a plan for providing reasonable assurance of funds for future decommissioning. The Company has external trust funds (Funds) to comply with the NRC's regulations. Use of the Funds is restricted to nuclear decommissioning activities. The Funds are managed and invested in accordance with applicable requirements of various regulatory bodies, including the NRC, the FERC, and the Alabama PSC, as well as the Internal Revenue Service (IRS). The Funds are required to be held by one or more trustees with an individual net worth of at least $100 million. The FERC requires the Funds' managers to exercise the standard of care in investing that a "prudent investor" would use in the same circumstances. The FERC regulations also require that the Funds' managers may not invest in any securities of the utility for which it manages funds or its affiliates, except for investments tied to market indices or other mutual funds. While the Company is allowed to prescribe an overall investment policy to the Funds' managers, the Company and its affiliates are not allowed to engage in the day-to-day management of the Funds or to mandate individual investment decisions. Day-to-day management of the investments in the Funds is delegated to unrelated third party managers with oversight by the management of the Company. The Funds' managers are authorized, within certain investment guidelines, to actively buy and sell securities at their own discretion in order to maximize the return on the Funds' investments. The Funds are invested in a tax-efficient manner in a diversified mix of equity and fixed income securities and are reported as trading securities.
The Company records the investment securities held in the Funds at fair value, as disclosed in Note 10, as management believes that fair value best represents the nature of the Funds. Gains and losses, whether realized or unrealized, are recorded in the regulatory liability for asset retirement obligations in the balance sheets and are not included in net income or OCI. Fair value adjustments and realized gains and losses are determined on a specific identification basis.
At December 31, 2013, investment securities in the Funds totaled $713 million, consisting of equity securities of $566 million, debt securities of $131 million, and $16 million of other securities. At December 31, 2012, investment securities in the Funds totaled $604 million, consisting of equity securities of $438 million, debt securities of $156 million, and $10 million of other securities. These amounts exclude receivables related to investment income and pending investment sales and payables related to pending investment purchases.
Sales of the securities held in the Funds resulted in cash proceeds of $279 million, $193 million, and $349 million in 2013, 2012, and 2011, respectively, all of which were reinvested. For 2013, fair value increases, including reinvested interest and dividends and excluding the Funds' expenses, were $120 million, of which $5 million related to realized gains and $85 million related to unrealized gains related to securities held in the Funds at December 31, 2013. For 2012, fair value increases, including reinvested interest and dividends and excluding the Funds' expenses, were $70 million, of which $4 million related to realized gains and $50 million related to unrealized gains related to securities held in the Funds at December 31, 2012. For 2011, fair value increases, including reinvested interest and dividends and excluding the Funds' expenses, were $6 million, of which $41 million related to realized gains and $51 million related to unrealized losses related to securities held in the Funds at December 31, 2011. 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 and purpose for which the securities were acquired.
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. The Company has filed a plan with the NRC designed to ensure that, over time, the deposits and earnings of the Funds will provide the minimum funding amounts prescribed by the NRC.
At December 31, the accumulated provisions for decommissioning were as follows:

	2013	2012

	(in millions)	
External trust funds	$713	$604
Internal reserves	21	22
Total	$734	$626

NOTES (continued)
Alabama Power Company 2013 Annual Report

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

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

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

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

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

Allowance for Funds Used During Construction

In accordance with regulatory treatment, the Company records allowance for funds used during construction (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. All current construction costs are included in retail rates. The composite rate used to determine the amount of AFUDC was 9.1% in 2013, 9.4% in 2012, and 9.2% in 2011. AFUDC, net of income taxes, as a percent of net income after dividends on preferred and preference stock was 5.4% in 2013, 3.3% in 2012, and 3.9% in 2011.

Impairment of Long-Lived Assets and Intangibles

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

Natural Disaster Reserve

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

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. See Note 3 under "Retail Regulatory Matters – Natural Disaster Reserve" herein for additional information.

Cash and Cash Equivalents

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

Materials and Supplies

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

Fuel Inventory

Fuel inventory includes the average cost of coal, natural gas, 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 Company through energy cost recovery rates approved by the Alabama PSC. Emissions allowances granted by the U.S. Environmental Protection Agency (EPA) are included in inventory at zero cost.

Financial Instruments

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

The Company does not offset fair value amounts recognized for multiple derivative instruments executed with the same counterparty under a master netting arrangement. Additionally, the Company had no outstanding collateral repayment obligations and had immaterial reclaim collateral arising from derivative instruments recognized at December 31, 2013.

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

Comprehensive Income

The objective of comprehensive income is to report a measure of all changes in common stock equity of an enterprise that result from transactions and other economic events of the period other than transactions with owners. Comprehensive income consists of net income, changes in the fair value of qualifying cash flow hedges, and reclassifications for amounts included in net income.

Variable Interest Entities

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

The Company has established a wholly-owned trust to issue preferred securities. See Note 6 under "Long-Term Debt Payable to an Affiliated Trust" for additional information. However, the Company is not considered the primary beneficiary of the trust.

NOTES (continued)
Alabama Power Company 2013 Annual Report

Therefore, the investment in the trust is reflected as other investments, and the related loan from the trust is reflected as long-term debt in the balance sheets.

2. RETIREMENT BENEFITS

The Company has a defined benefit, trusteed, pension plan covering substantially all employees. This qualified pension plan is funded in accordance with requirements of the Employee Retirement Income Security Act of 1974, as amended (ERISA). No contributions were made to the qualified pension plan during 2013. No mandatory contributions to the qualified pension plan are anticipated for the year ending December 31, 2014. The Company also provides certain defined benefit pension plans for a selected group of management and highly compensated employees. Benefits under these non-qualified pension plans are funded on a cash basis. In addition, the Company provides certain medical care and life insurance benefits for retired employees through other postretirement benefit plans. The Company funds its other postretirement trusts to the extent required by the Alabama PSC and the FERC. No contributions to the other postretirement trusts are expected during the year ending December 31, 2014.

Actuarial Assumptions

The weighted average rates assumed in the actuarial calculations used to determine both the benefit obligations as of the measurement date and the net periodic costs for the pension and other postretirement benefit plans for the following year are presented below. Net periodic benefit costs were calculated in 2010 for the 2011 plan year using discount rates for the pension plans and the other postretirement benefit plans of 5.52% and 5.41%, respectively, and an annual salary increase of 3.84%.

	2013		2012		2011	
Discount rate:						
Pension plans	5.02	%	4.27	%	4.98	%
Other postretirement benefit plans	4.86		4.06		4.88	
Annual salary increase	3.59		3.59		3.84	
Long-term return on plan assets:						
Pension plans	8.20		8.20		8.45	
Other postretirement benefit plans	7.36		7.19		7.39	

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

An additional assumption used in measuring the accumulated other postretirement benefit obligations (APBO) was a weighted average medical care cost trend rate of 7.00% for 2014, decreasing gradually to 5.00% through the year 2021 and remaining at that level thereafter. 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, 2013 as follows:

	1 Percent Increase	1 Percent Decrease	
	(in millions)		
Benefit obligation	$26	$(22	)
Service and interest costs	1	(1	)

Table of Contents Index to Financial Statements

NOTES (continued)
Alabama Power Company 2013 Annual Report

Pension Plans

The total accumulated benefit obligation for the pension plans was $1.9 billion at December 31, 2013 and $2.0 billion at December 31, 2012. Changes in the projected benefit obligations and the fair value of plan assets during the plan years ended December 31, 2013 and 2012 were as follows:

	2013	2012
	(in millions)	
Change in benefit obligation		
Benefit obligation at beginning of year	$2,218	$1,932
Service cost	52	44
Interest cost	93	94
Benefits paid	(93)	(90)
Actuarial (gain) loss	(158)	238
Balance at end of year	2,112	2,218
Change in plan assets		
Fair value of plan assets at beginning of year	2,077	1,885
Actual return on plan assets	285	274
Employer contributions	9	8
Benefits paid	(93)	(90)
Fair value of plan assets at end of year	2,278	2,077
Prepaid pension costs (accrued liability)	$166	$(141)

At December 31, 2013, the projected benefit obligations for the qualified and non-qualified pension plans were $2.0 billion and $110 million, respectively. All pension plan assets are related to the qualified pension plan.

Amounts recognized in the balance sheets at December 31, 2013 and 2012 related to the Company's pension plans consist of the following:

	2013	2012
	(in millions)	
Prepaid pension costs	$276	$—
Other regulatory assets, deferred	476	822
Other current liabilities	(9)	(8)
Employee benefit obligations	(101)	(133)

Presented below are the amounts included in regulatory assets at December 31, 2013 and 2012 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 2014.

	2013	2012	Estimated Amortization in 2014
		(in millions)	
Prior service cost	$19	$26	$7
Net (gain) loss	457	796	31
Regulatory assets	$476	$822	

NOTES (continued)
Alabama Power Company 2013 Annual Report

The changes in the balance of regulatory assets related to the defined benefit pension plans for the years ended December 31, 2013 and 2012 are presented in the following table:

	2013	2012
	(in millions)	
Regulatory assets:		
Beginning balance	$822	$727
Net (gain) loss	(287)	125
Reclassification adjustments:		
Amortization of prior service costs	(7)	(7)
Amortization of net gain (loss)	(52)	(23)
Total reclassification adjustments	(59)	(30)
Total change	(346)	95
Ending balance	$476	$822

Components of net periodic pension cost (income) were as follows:

	2013	2012	2011
	(in millions)		
Service cost	$52	$44	$43
Interest cost	93	94	96
Expected return on plan assets	(157)	(162)	(173)
Recognized net (gain) loss	52	23	4
Net amortization	7	7	9
Net periodic pension cost (income)	$47	$6	$(21)

Net periodic pension cost (income) 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, 2013, estimated benefit payments were as follows:

	Benefit Payments
	(in millions)
2014	$104
2015	108
2016	113
2017	118
2018	122
2019 to 2023	669

NOTES (continued)
Alabama Power Company 2013 Annual Report

Other Postretirement Benefits
Changes in the APBO and in the fair value of plan assets during the plan years ended December 31, 2013 and 2012 were as follows:

	2013	2012
	(in millions)	
Change in benefit obligation		
Benefit obligation at beginning of year	$490	$470
Service cost	6	5
Interest cost	19	22
Benefits paid	(24)	(24)
Actuarial (gain) loss	(62)	15
Retiree drug subsidy	2	2
Balance at end of year	431	490
Change in plan assets		
Fair value of plan assets at beginning of year	343	315
Actual return on plan assets	61	39
Employer contributions	7	11
Benefits paid	(22)	(22)
Fair value of plan assets at end of year	389	343
Accrued liability	$(42)	$(147)

Amounts recognized in the balance sheets at December 31, 2013 and 2012 related to the Company's other postretirement benefit plans consist of the following:

	2013	2012
	(in millions)	
Other regulatory assets, deferred	$6	$89
Other regulatory liabilities, deferred	(21)	—
Employee benefit obligations	(42)	(147)

NOTES (continued)
Alabama Power Company 2013 Annual Report

Presented below are the amounts included in net regulatory assets (liabilities) at December 31, 2013 and 2012 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 2014.

	2013	2012	Estimated Amortization in 2014
	(in millions)		
Prior service cost	$19	$22	$4
Net (gain) loss	(34)	67	—
Net regulatory assets (liabilities)	$(15)	$89	

The changes in the balance of net regulatory assets (liabilities) related to the other postretirement benefit plans for the plan years ended December 31, 2013 and 2012 are presented in the following table:

	2013	2012
	(in millions)	
Net regulatory assets (liabilities):		
Beginning balance	$89	$96
Net gain	(99)	(1)
Reclassification adjustments:		
Amortization of transition obligation	—	(2)
Amortization of prior service costs	(3)	(4)
Amortization of net gain (loss)	(2)	—
Total reclassification adjustments	(5)	(6)
Total change	(104)	(7)
Ending balance	$(15)	$89

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

	2013	2012	2011
	(in millions)		
Service cost	$6	$5	$5
Interest cost	19	22	24
Expected return on plan assets	(23)	(23)	(25)
Net amortization	5	6	7
Net periodic postretirement benefit cost	$7	$10	$11

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)		
2014	$30	$(3)	$27
2015	31	(3)	28
2016	31	(3)	28
2017	33	(4)	29
2018	33	(4)	29

2019 to 2023	164	(22)	142

NOTES (continued)
Alabama Power Company 2013 Annual Report

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, 2013 and 2012, along with the targeted mix of assets for each plan, is presented below:

	Target	2013	2012
Pension plan assets:			
Domestic equity	26 %	31 %	28 %
International equity	25	25	24
Fixed income	23	23	27
Special situations	3	1	1
Real estate investments	14	14	13
Private equity	9	6	7
Total	100 %	100 %	100 %
Other postretirement benefit plan assets:			
Domestic equity	44 %	47 %	46 %
International equity	20	20	20
Domestic fixed income	24	27	28
Special situations	1	—	—
Real estate investments	8	4	4
Private equity	3	2	2
Total	100 %	100 %	100 %

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

Table of Contents Index to Financial Statements

NOTES (continued)
Alabama Power Company 2013 Annual Report

- 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, 2013 and 2012. 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.

Table of Contents Index to Financial Statements

NOTES (continued)
Alabama Power Company 2013 Annual Report

The fair values of pension plan assets as of December 31, 2013 and 2012 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.

As of December 31, 2013:	Fair Value Measurements Using Quoted Prices in Active Markets for Identical Assets (Level 1) (in millions)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)	Total
Assets:				
Domestic equity*	$374	$219	$—	$593
International equity*	287	265	—	552
Fixed income:				
U.S. Treasury, government, and agency bonds	—	156	—	156
Mortgage- and asset-backed securities	—	41	—	41
Corporate bonds	—	255	—	255
Pooled funds	—	123	—	123
Cash equivalents and other	—	58	—	58
Real estate investments	68	—	261	329
Private equity	—	—	149	149
Total	$729	$1,117	$410	$2,256
Liabilities:				
Derivatives	—	(1)	—	(1)
Total	$729	$1,116	$410	$2,255

* 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.

Table of Contents Index to Financial Statements

NOTES (continued)
Alabama Power Company 2013 Annual Report

As of December 31, 2012:	Fair Value Measurements Using Quoted Prices in Active Markets for Identical Assets (Level 1) (in millions)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)	Total
Assets:				
Domestic equity*	$304	$175	$—	$479
International equity*	238	256	—	494
Fixed income:				
U.S. Treasury, government, and agency bonds	—	135	—	135
Mortgage- and asset-backed securities	—	33	—	33
Corporate bonds	—	230	1	231
Pooled funds	—	104	—	104
Cash equivalents and other	1	143	—	144
Real estate investments	67	—	220	287
Private equity	—	—	155	155
Total	$610	$1,076	$376	$2,062

* 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.

Changes in the fair value measurement of the Level 3 items in the pension plan assets valued using significant unobservable inputs for the years ended December 31, 2013 and 2012 were as follows:

	2013 Real Estate Investments (in millions)	2013 Private Equity	2012 Real Estate Investments	2012 Private Equity
Beginning balance	$220	$155	$217	$161
Actual return on investments:				
Related to investments held at year end	19	2	2	—
Related to investments sold during the year	8	13	1	2
Total return on investments	27	15	3	2
Purchases, sales, and settlements	14	(21)	—	(8)
Ending balance	$261	$149	$220	$155

The fair values of other postretirement benefit plan assets as of December 31, 2013 and 2012 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.

NOTES (continued)
Alabama Power Company 2013 Annual Report

As of December 31, 2013:	Fair Value Measurements Using Quoted Prices in Active Markets for Identical Assets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)	Total
	(in millions)			
Assets:				
Domestic equity*	$67	$11	$—	$78
International equity*	14	13	—	27
Fixed income:				
U.S. Treasury, government, and agency bonds	—	17	—	17
Mortgage- and asset-backed securities	—	2	—	2
Corporate bonds	—	12	—	12
Pooled funds	—	6	—	6
Cash equivalents and other	—	10	—	10
Trust-owned life insurance	—	211	—	211
Real estate investments	4	—	13	17
Private equity	—	—	7	7
Total	$85	$282	$20	$387

* 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, 2012:	Fair Value Measurements Using Quoted Prices in Active Markets for Identical Assets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)	Total
	(in millions)			
Assets:				
Domestic equity*	$62	$9	$—	$71
International equity*	12	13	—	25
Fixed income:				
U.S. Treasury, government, and agency bonds	—	7	—	7
Mortgage- and asset-backed securities	—	2	—	2
Corporate bonds	—	11	—	11
Pooled funds	—	5	—	5
Cash equivalents and other	—	19	—	19
Trust-owned life insurance	—	178	—	178
Real estate investments	4	—	11	15
Private equity	—	—	8	8
Total	$78	$244	$19	$341

* 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.

Table of Contents Index to Financial Statements

NOTES (continued)
Alabama Power Company 2013 Annual Report

Changes in the fair value measurement of the Level 3 items in the other postretirement benefit plan assets valued using significant unobservable inputs for the years ended December 31, 2013 and 2012 were as follows:

	2013		2012	
	Real Estate Investments (in millions)	Private Equity	Real Estate Investments	Private Equity
Beginning balance	$11	$8	$11	$8
Actual return on investments:				
Related to investments held at year end	1	—	—	—
Related to investments sold during the year	—	—	—	—
Total return on investments	1	—	—	—
Purchases, sales, and settlements	1	(1)	—	—
Ending balance	$13	$7	$11	$8

Employee Savings Plan

The Company also sponsors a 401(k) defined contribution plan covering substantially all employees. The Company provides an 85% matching contribution on up to 6% of an employee's base salary. Total matching contributions made to the plan for 2013, 2012, and 2011 were $20 million, $19 million, and $18 million, respectively.

3. CONTINGENCIES AND REGULATORY MATTERS

General Litigation Matters

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

Environmental Matters

New Source Review Actions

As part of a nationwide enforcement initiative against the electric utility industry which began in 1999, the EPA brought civil enforcement actions in federal district court against the Company alleging violations of the New Source Review (NSR) provisions of the Clean Air Act at certain coal-fired electric generating units, including a unit co-owned by Mississippi Power. These civil actions seek penalties and injunctive relief, including orders requiring installation of the best available control technologies at the affected units. The case against the Company (including claims involving a unit co-owned by Mississippi Power) has been actively litigated in the U.S. District Court for the Northern District of Alabama, resulting in a settlement in 2006 of the alleged NSR violations at Plant Miller; voluntary dismissal of certain claims by the EPA; and a grant of summary judgment for the Company on all remaining claims and dismissal of the case with prejudice in 2011. On September 19, 2013, the U.S. Court of Appeals for the Eleventh Circuit affirmed in part and reversed in part the 2011 judgment in favor of the Company, and the case has been transferred back to the U.S. District Court for the Northern District of Alabama for further proceedings.

The Company believes it complied with applicable laws and regulations in effect at the time the work in question took place. The Clean Air Act authorizes maximum civil penalties of $25,000 to $37,500 per day, per violation, depending on the date of the alleged violation. An adverse outcome could require substantial capital expenditures that cannot be determined at this time and could possibly require payment of substantial penalties. Such expenditures could affect future results of operations, cash flows, and financial condition if such costs are not recovered through regulated rates. The ultimate outcome of this matter cannot be determined at this time.

NOTES (continued)
Alabama Power Company 2013 Annual Report

Environmental Remediation
The Company must comply with environmental laws and regulations that cover the handling and disposal of waste and releases of hazardous substances. Under these various laws and regulations, the Company could incur substantial costs to clean up properties. The Company conducts studies to determine the extent of any required cleanup and has recognized in its financial statements the costs to clean up known sites. Amounts for cleanup and ongoing monitoring costs were not material for any year presented. The Company may be liable for some or all required cleanup costs for additional sites that may require environmental remediation.
Nuclear Fuel Disposal Costs
Acting through the U.S. Department of Energy (DOE) and pursuant to the Nuclear Waste Policy Act of 1982, the U.S. government entered into a contract with the Company that requires the DOE to dispose of spent nuclear fuel and high level radioactive waste generated at Plant Farley. The DOE failed to timely perform and has yet to commence the performance of its contractual and statutory obligation to dispose of spent nuclear fuel beginning no later than January 31, 1998. Consequently, the Company has pursued and continues to pursue legal remedies against the U.S. government for its partial breach of contract.
As a result of the first lawsuit, the Company recovered approximately $17 million, representing the vast majority of the Company's direct costs of the expansion of spent nuclear fuel storage facilities at Plant Farley from 1998 through 2004. In April 2012, the award was credited to cost of service for the benefit of customers.
In 2008, the Company filed a second lawsuit against the U.S. government for the costs of continuing to store spent nuclear fuel at Plant Farley. Damages are being sought for the period from January 1, 2005 through December 31, 2010. 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, 2013 for any potential recoveries from the second lawsuit. The final outcome of this matter cannot be determined at this time; however, no material impact on the Company's net income is expected.
At Plant Farley, on-site dry spent fuel storage facilities are operational and can be expanded to accommodate spent fuel through the expected life of the plant.
Retail Regulatory Matters
Retail Rate Adjustments
In 2011, the Alabama PSC issued an order to eliminate a tax-related adjustment under the Company's rate structure effective with October 2011 billings. The elimination of this adjustment resulted in additional revenues of approximately $31 million for 2011. In accordance with the order, the Company made additional accruals to the NDR in the fourth quarter 2011 of an amount equal to such additional 2011 revenues. The NDR was impacted as a result of operations and maintenance expenses incurred in connection with the 2011 storms in Alabama. See "Natural Disaster Reserve" below for additional information. The elimination of this adjustment resulted in additional revenues of approximately $106 million for 2012.
Rate RSE
Rate stabilization and equalization plan (Rate RSE) adjustments are based on forward-looking information for the applicable upcoming calendar year. Rate adjustments for any two-year period, when averaged together, cannot exceed 4.0% and any annual adjustment is limited to 5.0%. If the Company's actual retail return is above the allowed equity return range, customer refunds will be required; however, there is no provision for additional customer billings should the actual retail return fall below the allowed equity return range. Prior to 2014, retail rates remained unchanged when the retail return on common equity (ROE) was projected to be between 13.0% and 14.5%.
During 2013, the Alabama PSC held public proceedings regarding the operation and utilization of Rate RSE. On August 13, 2013, the Alabama PSC voted to issue a report on Rate RSE that found that the Company's Rate RSE mechanism continues to be just and reasonable to customers and the Company, but recommended the Company modify Rate RSE as follows:
- Eliminate the provision of Rate RSE establishing an allowed range of ROE.

- Eliminate the provision of Rate RSE limiting the Company's capital structure to an allowed equity ratio of 45%.
- Replace these two provisions with a provision that establishes rates based upon an allowed weighted cost of equity (WCE) range of 5.75% to 6.21%, with an adjusting point of 5.98%. If calculated under the previous Rate RSE provisions, the resulting WCE would range from 5.85% to 6.53%, with an adjusting point of 6.19%.

NOTES (continued)
Alabama Power Company 2013 Annual Report

- Provide eligibility for a performance-based adder of seven basis points, or 0.07%, to the WCE adjusting point if the Company (i) has an "A" credit rating equivalent with at least one of the recognized rating agencies or (ii) is in the top one-third of a designated customer value benchmark survey.

Substantially all other provisions of Rate RSE were unchanged.

On August 21, 2013, the Company filed its consent to these recommendations with the Alabama PSC. The changes became effective for calendar year 2014. On November 27, 2013, the Company made its Rate RSE submission to the Alabama PSC of projected data for calendar year 2014; projected earnings were within the specified WCE range and, therefore, retail rates under Rate RSE remained unchanged for 2014. In 2012 and 2013, retail rates under Rate RSE remained unchanged from 2011. Under the terms of Rate RSE, the maximum possible increase for 2015 is 5.00%.

Rate CNP

The Company's retail rates, approved by the Alabama PSC, provide for adjustments to recognize the placing of new generating facilities into retail service under rate certificated new plant (Rate CNP). The Company may also recover retail costs associated with certificated PPAs under rate certificated new plant (Rate CNP PPA). There was no adjustment to Rate CNP PPA in 2012. On March 5, 2013, the Alabama PSC issued a consent order that the Company leave in effect the current Rate CNP PPA factor for billings for the period April 1, 2013 through March 31, 2014. It is anticipated that no adjustment will be made to Rate CNP PPA in 2014. As of December 31, 2013, the Company had an under recovered certificated PPA balance of $18 million, all of which is included in deferred under recovered regulatory clause revenues in the balance sheet.

In 2011, the Alabama PSC approved and certificated a PPA of approximately 200 megawatts (MWs) of energy from wind-powered generating facilities which became operational in December 2012. In September 2012, the Alabama PSC approved and certificated a second wind PPA of approximately 200 MWs which became operational in January 2014. The terms of the wind PPAs permit the Company to use the energy and retire the associated environmental attributes in service of its customers or to sell environmental attributes, separately or bundled with energy. The Company has elected the normal purchase normal sale (NPNS) scope exception under the derivative accounting rules for its two wind PPAs, which total approximately 400 MWs. The NPNS exception allows the PPAs to be recorded at a cost, rather than fair value, basis. The industry's application of the NPNS exception to certain physical forward transactions in nodal markets is currently under review by the SEC at the request of the electric utility industry. The outcome of the SEC's review cannot now be determined. If the Company is ultimately required to record these PPAs at fair value, an offsetting regulatory asset or regulatory liability will be recorded.

Rate certificated new plant environmental (Rate CNP Environmental) also allows for the recovery of the Company's retail costs associated with environmental laws, regulations, or other such mandates. Rate CNP Environmental is based on forward-looking information and provides for the recovery of these costs pursuant to a factor that is calculated annually. Environmental costs to be recovered include operations and maintenance expenses, depreciation, and a return on certain invested capital. There was no adjustment to Rate CNP Environmental in 2012 or 2013. On August 13, 2013, the Alabama PSC approved the Company's petition requesting a revision to Rate CNP Environmental that allows recovery of costs related to pre-2005 environmental assets previously being recovered through Rate RSE. The revenue impact as a result of this revision is estimated to be $58 million in 2014. On November 21, 2013, the Company submitted calculations associated with its cost of complying with environmental mandates, as provided under Rate CNP Environmental. The filing reflected a projected unrecovered retail revenue requirement for environmental compliance of approximately $72 million, which is to be recovered in the billing months of January 2014 through December 2014. On December 3, 2013, the Alabama PSC issued a consent order that the Company leave in effect for 2014 the factors associated with the Company's environmental compliance costs for the year 2013. Any unrecovered amounts associated with 2014 will be reflected in the 2015 filing. As of December 31, 2013, the Company had an under recovered environmental clause balance of $7 million which is included in deferred under recovered regulatory clause revenues in the balance sheet.

Environmental Accounting Order

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

Compliance and Pension Cost Accounting Order

In November 2012, the Alabama PSC approved an accounting order to defer to a regulatory asset account certain compliance-related operations and maintenance expenditures for the years 2013 through 2017, as well as the incremental increase in

NOTES (continued)
Alabama Power Company 2013 Annual Report

operations expense related to pension cost for 2013. These deferred costs are to be amortized over a three-year period beginning in January 2015. The compliance related expenditures were related to (i) standards addressing Critical Infrastructure Protection issued by the North American Electric Reliability Corporation, (ii) cyber security requirements issued by the NRC, and (iii) NRC guidance addressing the readiness at nuclear facilities within the U.S. for severe events. The compliance-related expenses to be afforded regulatory asset treatment over the five-year period are currently estimated to be approximately $37 million. The amount of operations and maintenance expenses deferred to a regulatory asset in 2013 associated with compliance-related expenditures and pension cost was approximately $8 million and $12 million, respectively. Pursuant to the accounting order, the Company has the ability to accelerate the amortization of the regulatory assets with notification to the Alabama PSC.

Retail Energy Cost Recovery

The Company has established energy cost recovery rates under the Company's energy cost recovery rate (Rate ECR) as approved by the Alabama PSC. Rates are based on an estimate of future energy costs and the current over or under recovered balance. Revenues recognized under Rate ECR and recorded on the financial statements are adjusted for the difference in actual recoverable fuel costs and amounts billed in current regulated rates. The difference in the recoverable fuel costs and amounts billed give rise to the over or under recovered amounts recorded as regulatory assets or liabilities. The Company, along with the Alabama PSC, continually monitors the over or under recovered cost balance to determine whether an adjustment to billing rates is required. Changes in the Rate ECR factor have no significant effect on the Company's net income, but will impact operating cash flows. Currently, the Alabama PSC may approve billing rates under Rate ECR of up to 5.910 cents per kilowatt hour (KWH). On December 3, 2013, the Alabama PSC issued a consent order that the Company leave in effect the energy cost recovery rates which began in April 2011 for 2014. Therefore, the Rate ECR factor as of January 1, 2014 remained at 2.681 cents per KWH. Effective with billings beginning in January 2015, the Rate ECR factor will be 5.910 cents per KWH, absent a further order from the Alabama PSC.

The Company's over recovered fuel costs at December 31, 2013 totaled $42 million as compared to under recovered fuel costs of $4 million at December 31, 2012. At December 31, 2013, $27 million is included in other regulatory liabilities, current and $15 million is included in deferred over recovered regulatory clause revenues. The under recovered fuel costs at December 31, 2012 are included in deferred under recovered regulatory clause revenues in the balance sheets. These classifications are based on estimates, which include such factors as weather, generation availability, energy demand, and the price of energy. A change in any of these factors could have a material impact on the timing of any recovery of the under recovered fuel costs.

Natural Disaster Reserve

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

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.

In accordance with the order that was issued by the Alabama PSC in 2011 to eliminate a tax-related adjustment under the Company's rate structure that resulted in additional revenues, the Company made additional accruals to the NDR in the fourth quarter 2011 of an amount equal to the additional 2011 revenues, which were approximately $31 million. The accumulated balances in the NDR for the years ended December 31, 2013 and December 31, 2012 were approximately $96 million and $103 million, respectively. Any accruals to the NDR are included in the balance sheets under other regulatory liabilities, deferred and are reflected as other operations and maintenance expenses in the statements of income.

NOTES (continued)
Alabama Power Company 2013 Annual Report

Nuclear Outage Accounting Order

In accordance with a 2010 Alabama PSC order, nuclear outage operations and maintenance expenses for the two units at Plant Farley are deferred to a regulatory asset when the charges actually occur and are then amortized over the subsequent 18-month operational cycle.

Approximately $31 million of nuclear outage costs from the spring of 2012 was amortized to nuclear operations and maintenance expenses over the 18-month period ended in December 2013. During the spring of 2013, approximately $28 million of nuclear outage costs was deferred to a regulatory asset, and beginning in July 2013, these deferred costs are being amortized over an 18-month period. During the fall of 2013, approximately $32 million of nuclear outage costs associated with the second unit was deferred to a regulatory asset, and beginning in January 2014, these deferred costs are being amortized over an 18-month period. The Company will continue the pattern of deferral of nuclear outage expenses as incurred and the recognition of expenses over a subsequent 18-month period pursuant to the Alabama PSC order.

Non-Nuclear Outage Accounting Order

On August 13, 2013, the Alabama PSC approved the Company's petition requesting authorization to defer to a regulatory asset account certain operations and maintenance expenses associated with planned outages at non-nuclear generation facilities in 2014 and to amortize those expenses over a three-year period beginning in 2015. The 2014 outage expenditures to be deferred and amortized are estimated to total approximately $78 million.

4. JOINT OWNERSHIP AGREEMENTS

The Company and Georgia Power own equally all of the outstanding capital stock of SEGCO, which owns electric generating units with a total rated capacity of 1,020 MWs, as well as associated transmission facilities. The capacity of these units is sold equally to the Company and Georgia Power under a power contract. The Company and Georgia Power make payments sufficient to provide for the operating expenses, taxes, interest expense, and ROE. The Company's share of purchased power totaled $88 million in 2013, $109 million in 2012, and $142 million in 2011 and is included in "Purchased power from affiliates" in the statements of income. The Company accounts for SEGCO using the equity method.

In addition, the Company has guaranteed unconditionally the obligation of SEGCO under an installment sale agreement for the purchase of certain pollution control facilities at SEGCO's generating units, pursuant to which $25 million principal amount of pollution control revenue bonds are outstanding. The Company has guaranteed $100 million principal amount of unsecured senior notes issued by SEGCO for general corporate purposes. These senior notes mature on December 1, 2018. The Company had guaranteed $50 million principal amount of unsecured senior notes issued by SEGCO for general corporate purposes, which matured on May 15, 2013. Georgia Power has agreed to reimburse the Company for the pro rata portion of such obligations corresponding to its then proportionate ownership of stock of SEGCO if the Company is called upon to make such payment under its guarantee.

At December 31, 2013, the capitalization of SEGCO consisted of $84 million of equity and $125 million of long-term debt on which the annual interest requirement is $3 million. SEGCO paid dividends of $7 million in 2013, $14 million in 2012, and $15 million in 2011, of which one-half of each was paid to the Company. In addition, the Company recognizes 50% of SEGCO's net income.

SEGCO plans to add natural gas as the primary fuel source in 2015 for 1,000 MWs of its generating capacity. It is currently planning, developing, and constructing the necessary natural gas pipeline. The Company, which owns and operates a generating unit adjacent to the SEGCO generating units, has entered into a joint ownership agreement with SEGCO for the ownership of the gas pipeline. The Company will own 14% of the pipeline with the remaining 86% owned by SEGCO. At December 31, 2013, the Company's portion of the construction work in progress associated with the pipeline is $1 million.

NOTES (continued)
Alabama Power Company 2013 Annual Report

In addition to the Company's ownership of SEGCO and joint ownership of the natural gas pipeline, the Company's percentage ownership and investment in jointly-owned coal-fired generating plants at December 31, 2013 were as follows:

Facility	Total Megawatt Capacity	Company Ownership		Plant in Service	Accumulated Depreciation	Construction Work in Progress
				(in millions)		
Greene County	500	60.00	% (1)	$157	$91	$5
Plant Miller Units 1 and 2	1,320	91.84	% (2)	1,410	575	89

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

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

5. INCOME TAXES

On behalf of the Company, Southern Company files a consolidated federal income tax return and combined state income tax returns for the States of Alabama, Georgia, and Mississippi. In addition, the Company files a separate company income tax return for the State of Tennessee. 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:

	2013	2012	2011
	(in millions)		
Federal —			
Current	$243	$262	$20
Deferred	160	137	377
	403	399	397
State —			
Current	36	51	(1)
Deferred	39	27	82
	75	78	81
Total	$478	$477	$478

NOTES (continued)
Alabama Power Company 2013 Annual Report

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:

	2013	2012
	(in millions)	
Deferred tax liabilities —		
Accelerated depreciation	$3,187	$2,989
Property basis differences	458	420
Premium on reacquired debt	33	36
Employee benefit obligations	209	218
Under recovered energy clause	—	16
Regulatory assets associated with employee benefit obligations	198	378
Asset retirement obligations	38	—
Regulatory assets associated with asset retirement obligations	265	248
Other	128	114
Total	4,516	4,419
Deferred tax assets —		
Federal effect of state deferred taxes	205	194
Unbilled fuel revenue	41	39
Storm reserve	32	34
Employee benefit obligations	231	408
Other comprehensive losses	18	19
Asset retirement obligations	303	248
Other	108	98
Total	938	1,040
Total deferred tax liabilities, net	3,578	3,379
Portion included in prepaid expenses (accrued income taxes)	25	25
Accumulated deferred income taxes	$3,603	$3,404

At December 31, 2013, the Company's tax-related regulatory assets to be recovered from customers were $519 million. These assets are primarily attributable to tax benefits that flowed through to customers in prior years, to deferred taxes previously recognized at rates lower than the current enacted tax law, and to taxes applicable to capitalized interest.

At December 31, 2013, the Company's tax-related regulatory liabilities to be credited to customers were $75 million. These liabilities are primarily attributable to unamortized ITCs.

In accordance with regulatory requirements, deferred ITCs are amortized over the life of the related property with such amortization normally applied as a credit to reduce depreciation in the statements of income. Credits amortized in this manner amounted to $8 million in each of 2013, 2012, and 2011. At December 31, 2013, all ITCs available to reduce federal income taxes payable had been utilized.

In 2010, the Tax Relief, Unemployment Insurance Reauthorization, and Job Creation Act of 2010 (Tax Relief Act) was signed into law. Major tax incentives in the Tax Relief Act include 100% bonus depreciation for property placed in service after September 8, 2010 and through 2011 (and for certain long-term production-period projects placed in service in 2012) and 50% bonus depreciation for property placed in service in 2012 (and for certain long-term production-period projects placed in service in 2013).

On January 2, 2013, the American Taxpayer Relief Act of 2012 (ATRA) was signed into law. The ATRA retroactively extended several tax credits through 2013 and extended 50% bonus depreciation for property placed in service in 2013 (and for certain long-term production-period projects to be placed in service in 2014).

The application of the bonus depreciation provisions in these laws significantly increased deferred tax liabilities related to accelerated depreciation in 2013, 2012, and 2011.

NOTES (continued)
Alabama Power Company 2013 Annual Report

Effective Tax Rate

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

	2013	2012	2011
Federal statutory rate	35.0 %	35.0 %	35.0 %
State income tax, net of federal deduction	4.0	4.1	4.3
Non-deductible book depreciation	1.0	0.9	0.8
Differences in prior years' deferred and current tax rates	(0.1)	(0.1)	(0.1)
AFUDC equity	(0.9)	(0.5)	(0.6)
Other	(0.1)	(0.3)	(0.4)
Effective income tax rate	38.9 %	39.1 %	39.0 %

The changes in the Company's 2013 and 2012 effective tax rates were not material.

Unrecognized Tax Benefits

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

	2013	2012	2011
		(in millions)	
Unrecognized tax benefits at beginning of year	$31	$32	$43
Tax positions from current periods	—	5	6
Tax positions from prior periods	(31)	(4)	(17)
Reductions due to settlements	—	(2)	—
Balance at end of year	$—	$31	$32

The tax positions decrease from prior periods for 2013 relates primarily to the tax accounting method change for repairs-generation assets. See "Tax Method of Accounting for Repairs" herein for additional information.

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

	2013	2012	2011
		(in millions)	
Tax positions impacting the effective tax rate	$—	$—	$5
Tax positions not impacting the effective tax rate	—	31	27
Balance of unrecognized tax benefits	$—	$31	$32

The tax positions not impacting the effective tax rate for 2012 relate to the timing difference associated with the tax accounting method change for repairs-generation assets. See "Tax Method of Accounting for Repairs" herein for additional 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 is as follows:

	2013	2012	2011
		(in millions)	
Interest accrued at beginning of year	$—	$1.9	$1.5
Interest reclassified due to settlements	—	(1.9)	—
Interest accrued during the year	—	—	0.4
Balance at end of year	$—	$—	$1.9

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

NOTES (continued)
Alabama Power Company 2013 Annual Report

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 2011. Southern Company has filed its 2012 federal income tax return and has received a full acceptance letter from the IRS; however, the IRS has not finalized its audit. For tax years 2012 and 2013, Southern Company was a participant in the Compliance Assurance Process of the IRS. The audits for the Company's state income tax returns have either been concluded, or the statute of limitations has expired, for years prior to 2007.

Tax Method of Accounting for Repairs

In 2011, the IRS published regulations on the deduction and capitalization of expenditures related to tangible property that generally apply for tax years beginning on or after January 1, 2014. Additionally, on April 30, 2013, the IRS issued Revenue Procedure 2013-24, which provides guidance for taxpayers related to the deductibility of repair costs associated with generation assets. Based on a review of the regulations, Southern Company incorporated provisions related to repair costs for generation assets into its consolidated 2012 federal income tax return and reversed all related unrecognized tax positions. On September 19, 2013, the IRS issued Treasury Decision 9636, "Guidance Regarding Deduction and Capitalization of Expenditures Related to Tangible Property," which are final tangible property regulations applicable to taxable years beginning on or after January 1, 2014. Southern Company is currently reviewing this new guidance. The ultimate outcome of this matter cannot be determined at this time; however, these regulations are not expected to have a material impact on the Company's financial statements.

6. FINANCING

Long-Term Debt Payable to an Affiliated Trust

The Company has formed a wholly-owned trust subsidiary for the purpose of issuing preferred securities. The proceeds of the related equity investments and preferred security sales were loaned back to the Company through the issuance of junior subordinated notes totaling $206 million as of December 31, 2013 and 2012, which constitute substantially all of the assets of this trust and are reflected in the balance sheets as long-term debt payable. The Company considers that the mechanisms and obligations relating to the preferred securities issued for its benefit, taken together, constitute a full and unconditional guarantee by it of the trust's payment obligations with respect to these securities. At each of December 31, 2013 and 2012, trust preferred securities of $200 million were outstanding. See Note 1 under "Variable Interest Entities" for additional information on the accounting treatment for this trust and the related securities.

Securities Due Within One Year

At December 31, 2013, the Company had no scheduled maturities of senior notes due within one year. At December 31, 2012, the Company had $250 million of senior notes due within one year.

Maturities of senior notes and pollution control revenue bonds through 2018 applicable to total long-term debt are as follows: $454 million in 2015; $200 million in 2016; and $561 million in 2017. There are no scheduled maturities in 2014 and 2018.

Pollution Control Revenue Bonds

Pollution control obligations represent loans to the Company from public authorities of funds or installment purchases of pollution control and solid waste disposal facilities financed by funds derived from sales by public authorities of revenue bonds. The Company is required to make payments sufficient for the authorities to meet principal and interest requirements of such bonds. The Company incurred no obligations related to the issuance of pollution control revenue bonds in 2013. The amount of tax-exempt pollution control revenue bonds outstanding at each of December 31, 2013 and 2012 was $1.2 billion, respectively.

Senior Notes

In December 2013, the Company issued $300 million aggregate principal amount of its Series 2013A 3.55% Senior Notes due December 1, 2023. The proceeds of these issuances were used for general corporate purposes, including the

Company's continuous construction program.

In November 2013, the Company's $250 million aggregate principal amount of its Series 2008B 5.80% Senior Notes due November 15, 2013 matured.

Table of Contents Index to Financial Statements

NOTES (continued)
Alabama Power Company 2013 Annual Report

At December 31, 2013 and 2012, the Company had $4.9 billion and $4.8 billion of senior notes outstanding, respectively. These senior notes are effectively subordinated to all secured debt of the Company which amounted to approximately $153 million at December 31, 2013.

Outstanding Classes of Capital Stock

The Company currently has preferred stock, Class A preferred stock, preference stock, and common stock authorized and outstanding. The Company's preferred stock and Class A preferred stock, without preference between classes, rank senior to the Company's preference stock and common stock with respect to payment of dividends and voluntary and involuntary dissolution. The preferred stock and Class A preferred stock of the Company contain a feature that allows the holders to elect a majority of the Company's board of directors if dividends are not paid for four consecutive quarters. Because such a potential redemption-triggering event is not solely within the control of the Company, the preferred stock and Class A preferred stock is presented as "Redeemable Preferred Stock" in a manner consistent with temporary equity under applicable accounting standards. The preference stock does not contain such a provision that would allow the holders to elect a majority of the Company's board. The Company's preference stock ranks senior to the common stock with respect to the payment of dividends and voluntary or involuntary dissolution. The Company's preferred stock is subject to redemption at a price equal to the par value plus a premium. The Company's Class A preferred stock is subject to redemption at a price equal to the stated capital. Certain series of the Company's preference stock are subject to redemption at a price equal to the stated capital plus a make-whole premium based on the present value of the liquidation amount and future dividends to the first stated capital redemption date and the other series of preference stock are subject to redemption at a price equal to the stated capital. Certain series of the Company's preferred stock are subject to redemption at the option of the Company on or after a specified date. Information for each outstanding series is in the table below:

Preferred/Preference Stock	Par Value/Stated Capital Per Share	Shares Outstanding	First Call Date	Redemption Price Per Share
4.92% Preferred Stock	$100	80,000	*	$103.23
4.72% Preferred Stock	$100	50,000	*	$102.18
4.64% Preferred Stock	$100	60,000	*	$103.14
4.60% Preferred Stock	$100	100,000	*	$104.20
4.52% Preferred Stock	$100	50,000	*	$102.93
4.20% Preferred Stock	$100	135,115	*	$105.00
5.83% Class A Preferred Stock	$25	1,520,000	8/1/2008	Stated Capital
5.20% Class A Preferred Stock	$25	6,480,000	8/1/2008	Stated Capital
5.30% Class A Preferred Stock	$25	4,000,000	4/1/2009	Stated Capital
5.625% Preference Stock	$25	6,000,000	1/1/2012	Stated Capital
6.450% Preference Stock	$25	6,000,000	*	**
6.500% Preference Stock	$25	2,000,000	*	**

* Redemption permitted any time after issuance
** Prior to 10/01/2017: Stated Value Plus Make-Whole Premium; after 10/01/2017: Stated Capital

Dividend Restrictions

The Company can only pay dividends to Southern Company out of retained earnings or paid-in-capital.

Assets Subject to Lien

The Company has granted liens on certain property in connection with the issuance of certain series of pollution control revenue bonds with an outstanding principal amount of $153 million as of December 31, 2013. 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.

Table of Contents Index to Financial Statements

NOTES (continued)
Alabama Power Company 2013 Annual Report

Bank Credit Arrangements

At December 31, 2013, committed credit arrangements with banks were as follows:

Expires[a]					Executable Term-Loans		Due Within One Year	
2014	2015	2018	Total	Unused	One Year	Two Years	Term Out	No Term Out
			(in millions)					
$238	$35	$1,030	$1,303	$1,303	$53	$—	$53	$185

(a) No credit arrangements expire in 2016 or 2017.

The Company expects to renew its credit agreements as needed, prior to expiration. Most of the credit arrangements require payment of a commitment fee based on the unused portion of the commitments or the maintenance of compensating balances with the banks. Commitment fees average less than 1/4 of 1% for the Company. Compensating balances are not legally restricted from withdrawal.

Most of the Company's credit arrangements with banks have covenants that limit the Company's debt to 65% of total capitalization, as defined in the arrangements. For purposes of calculating these covenants, long-term notes payable to affiliated trusts are excluded from debt but included in capitalization. Exceeding this debt level would result in a default under the credit arrangements. At December 31, 2013, the Company was in compliance with the debt limit covenants.

A portion of the unused credit with banks is allocated to provide liquidity support to the Company's variable rate pollution control revenue bonds and commercial paper program. The amount of variable rate pollution control revenue bonds requiring liquidity support was $793 million as of December 31, 2013. In addition, at December 31, 2013, the Company had $200 million of fixed rate pollution control revenue bonds that will be required to be remarketed within the next 12 months.

The Company borrows through commercial paper programs that have the liquidity support of committed bank credit arrangements. The Company may also make short-term borrowings through various other arrangements with banks. At December 31, 2013 and 2012, there was no short-term debt outstanding. At December 31, 2013, the Company had regulatory approval to have outstanding up to $2 billion of short-term borrowings.

7. COMMITMENTS

Fuel and Purchased Power Agreements

To supply a portion of the fuel requirements of its generating plants, the Company has entered into various long-term commitments for the procurement and delivery of fossil and nuclear fuel which are not recognized on the balance sheets. In 2013, 2012, and 2011, the Company incurred fuel expense of $1.6 billion, $1.5 billion, and $1.7 billion, respectively, the majority of which was purchased under long-term commitments. The Company expects that a substantial amount of its future fuel needs will continue to be purchased under long-term commitments.

In addition, the Company has entered into various long-term commitments for the purchase of capacity and electricity, some of which are accounted for as operating leases. Total capacity expense under PPAs accounted for as operating leases was $30 million, $33 million, and $33 million for 2013, 2012, and 2011, respectively. Total estimated minimum long-term obligations at December 31, 2013 were as follows:

	Operating Lease PPAs
	(in millions)
2014	$36
2015	38
2016	39
2017	40
2018	42
2019 and thereafter	182

Total commitments	$377

SCS may enter into various types of wholesale energy and natural gas contracts acting as an agent for the Company and all of the other Southern Company traditional operating companies and Southern Power. Under these agreements, each of the traditional operating companies and Southern Power may be jointly and severally liable. Accordingly, Southern Company has entered into keep-well agreements with the Company and each of the other traditional operating companies to ensure the Company will not subsidize or be responsible for any costs, losses, liabilities, or damages resulting from the inclusion of Southern Power as a contracting party under these agreements.

Operating Leases

The Company has entered into rental agreements for coal railcars, vehicles, and other equipment with various terms and expiration dates. Total rent expense was $21 million in 2013, $24 million in 2012, and $23 million in 2011. Of these amounts, $18 million, $19 million, and $18 million for 2013, 2012, and 2011, respectively, relate to the railcar leases and are recoverable through the Company's Rate ECR. As of December 31, 2013, estimated minimum lease payments under operating leases were as follows:

	Minimum Lease Payments		
	Railcars	Vehicles & Other	Total
	(in millions)		
2014	$12	$3	$15
2015	10	2	12
2016	11	1	12
2017	6	—	6
2018	4	—	4
2019 and thereafter	15	—	15
Total	$58	$6	$64

In addition to the above rental commitments payments, the Company has potential obligations upon expiration of certain leases with respect to the residual value of the leased property. These leases have terms expiring through 2023 with maximum obligations under these leases of $8 million in 2014, $5 million in 2015, $4 million in 2016, and $12 million in 2019 and thereafter. There are no maximum obligations under these leases in 2017 and 2018. At the termination of the leases, the lessee may either exercise its purchase option, or the property can be sold to a third party. The Company expects that the fair market value of the leased property would substantially reduce or eliminate the Company's payments under the residual value obligations.

Guarantees

The Company has guaranteed the obligation of SEGCO for $25 million of pollution control revenue bonds issued in 2001, which mature in June 2019, and also $100 million of senior notes issued in November 2013, which mature in December 2018. Georgia Power has agreed to reimburse the Company for the pro rata portion of such obligations corresponding to Georgia Power's then proportionate ownership of SEGCO's stock if the Company is called upon to make such payment under its guarantee. See Note 4 for additional information.

8. STOCK COMPENSATION

Stock Options

Southern Company provides non-qualified stock options through its Omnibus Incentive Compensation Plan to a large segment of the Company's employees ranging from line management to executives. As of December 31, 2013, there were approximately 1,000 current and former employees of the Company participating in the stock option program, and there were 28 million shares of Southern Company common stock remaining available for awards under the Omnibus Incentive Compensation Plan. The prices of options were at the fair market value of the shares on the dates of grant. These options become exercisable pro rata over a maximum period of three years from the date of grant. The Company generally recognizes stock option expense on a straight-line basis over the vesting period which equates to the requisite service period; however, for employees who are eligible for retirement, the total cost is expensed at the grant date. Options outstanding will expire no later than 10 years after the date of grant, unless terminated earlier by the Southern Company Board of Directors in accordance with the Omnibus Incentive Compensation Plan. Stock options held by employees of a company undergoing a change in control vest upon the change in control.

NOTES (continued)
Alabama Power Company 2013 Annual Report

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	2013	2012	2011
Expected volatility	16.6%	17.7%	17.5%
Expected term (in years)	5.0	5.0	5.0
Interest rate	0.9%	0.9%	2.3%
Dividend yield	4.4%	4.2%	4.8%
Weighted average grant-date fair value	$2.93	$3.39	$3.23

The Company's activity in the stock option program for 2013 is summarized below:

	Shares Subject to Option	Weighted Average Exercise Price
Outstanding at December 31, 2012	6,060,552	$36.02
Granted	1,319,038	44.07
Exercised	(1,035,611)	32.74
Cancelled	(4,271)	42.88
Outstanding at December 31, 2013	6,339,708	$38.23
Exercisable at December 31, 2013	4,021,541	$35.29

The number of stock options vested, and expected to vest in the future, as of December 31, 2013 was not significantly different from the number of stock options outstanding at December 31, 2013 as stated above. As of December 31, 2013, the weighted average remaining contractual term for the options outstanding and options exercisable was approximately six years and five years, respectively, and the aggregate intrinsic value for the options outstanding and options exercisable was $26 million and $25 million, respectively.
As of December 31, 2013, there was $1 million of total unrecognized compensation cost related to stock option awards not yet vested. That cost is expected to be recognized over a weighted-average period of approximately 11 months.
For the years ended December 31, 2013, 2012, and 2011, total compensation cost for stock option awards recognized in income was $4 million, $4 million, and $3 million, respectively, with the related tax benefit also recognized in income of $2 million, $1 million, and $1 million, respectively.
The compensation cost and tax benefits related to the grant and exercise of Southern Company stock options to the Company's employees are recognized in the Company's financial statements with a corresponding credit to equity, representing a capital contribution from Southern Company.
The total intrinsic value of options exercised during the years ended December 31, 2013, 2012, and 2011 was $11 million, $28 million, and $23 million, respectively. The actual tax benefit realized by the Company for the tax deductions from stock option exercises totaled $4 million, $11 million, and $9 million for the years ended December 31, 2013, 2012, and 2011, respectively.
Performance Shares
Southern Company provides performance share award units through its Omnibus Incentive Compensation Plan to a large segment of the Company's employees ranging from line management to executives. The performance share units granted under the plan vest at the end of a three-year performance period which equates to the requisite service period. Employees that retire prior to the end of the three-year period receive a pro rata number of shares, issued at the end of the performance period, based on actual months of service prior to retirement. The value of the award units is based on

Southern Company's total shareholder return (TSR) over the three-year performance period which measures Southern Company's relative performance against a group of industry peers. The performance shares are delivered in common stock following the end of the performance period based on Southern Company's actual TSR and may range from 0% to 200% of the original target performance share amount.

NOTES (continued)
Alabama Power Company 2013 Annual Report

The fair value of performance share awards is determined as of the grant date using a Monte Carlo simulation model to estimate the TSR of Southern Company's stock among the industry peers over the performance period. The Company recognizes compensation expense on a straight-line basis over the three-year performance period without remeasurement. Compensation expense for awards where the service condition is met is recognized regardless of the actual number of shares issued. 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 award units.
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	2013	2012	2011
Expected volatility	12.0%	16%	19.2%
Expected term (in years)	3.0	3.0	3.0
Interest rate	0.4%	0.4%	1.4%
Annualized dividend rate	$1.96	$1.89	$1.82
Weighted average grant-date fair value	$40.50	$41.99	$35.97

Total unvested performance share units outstanding as of December 31, 2012 were 280,536. During 2013, 141,355 performance share units were granted, 131,581 performance share units were vested, and 5,484 performance share units were forfeited resulting in 284,826 unvested units outstanding at December 31, 2013. In January 2014, the vested performance share award units were converted into 39,258 shares outstanding at a share price of $41.27 for the three-year performance and vesting period ended December 31, 2013.
For the years ended December 31, 2013, 2012, and 2011, total compensation cost for performance share units recognized in income was $5 million, $5 million, and $3 million, respectively, with the related tax benefit also recognized in income of $2 million, $2 million, and $1 million, respectively. As of December 31, 2013, there was $6 million of total unrecognized compensation cost related to performance share award units that will be recognized over a weighted-average period of approximately 11 months.

9. NUCLEAR INSURANCE

Under the Price-Anderson Amendments Act (Act), the Company maintains agreements of indemnity with the NRC that, together with private insurance, cover third-party liability arising from any nuclear incident occurring at Plant Farley. The Act provides funds up to $13.6 billion for public liability claims that could arise from a single nuclear incident. Plant Farley is insured against this liability to a maximum of $375 million by American Nuclear Insurers (ANI), with the remaining coverage provided by a mandatory program of deferred premiums that could be assessed, after a nuclear incident, against all owners of commercial nuclear reactors. The Company could be assessed up to $127 million per incident for each licensed reactor it operates but not more than an aggregate of $19 million per incident to be paid in a calendar year for each reactor. Such maximum assessment, excluding any applicable state premium taxes, for the Company is $255 million per incident but not more than an aggregate of $38 million to be paid for each incident in any one year. Both the maximum assessment per reactor and the maximum yearly assessment are adjusted for inflation at least every five years. The next scheduled adjustment is due no later than September 10, 2018.
The Company is a member of Nuclear Electric Insurance Limited (NEIL), a mutual insurer established to provide property damage insurance in an amount up to $500 million for members' operating nuclear generating facilities. Additionally, the Company has NEIL policies that currently provide decontamination, excess property insurance, and premature decommissioning coverage up to $2.25 billion for nuclear losses in excess of the $500 million primary coverage. These policies have a sublimit of $1.7 billion for non-nuclear losses.
NEIL also covers the additional costs that would be incurred in obtaining replacement power during a prolonged accidental outage at a member's nuclear plant. Members can purchase this coverage, subject to a deductible waiting period of up to 26 weeks, with a maximum per occurrence per unit limit of $490 million. After the deductible period, weekly indemnity payments would be received until either the unit is operational or until the limit is exhausted in

approximately three years. The Company purchases limits based on the projected full cost of replacement power and has elected a 12-week deductible waiting period.

Under each of the NEIL policies, members are subject to assessments each year if losses exceed the accumulated funds available to the insurer. The current maximum annual assessments for the Company under the NEIL policies would be $43 million.

Claims resulting from terrorist acts are covered under both the ANI and NEIL policies (subject to normal policy limits). The aggregate, however, that NEIL will pay for all claims resulting from terrorist acts in any 12-month period is $3.2 billion plus such additional amounts NEIL can recover through reinsurance, indemnity, or other sources.

For all on-site property damage insurance policies for commercial nuclear power plants, the NRC requires that the proceeds of such policies shall be dedicated first for the sole purpose of placing the reactor in a safe and stable condition after an accident. Any remaining proceeds are to be applied next toward the costs of decontamination and debris removal operations ordered by the NRC, and any further remaining proceeds are to be paid either to the Company or to its debt trustees as may be appropriate under the policies and applicable trust indentures. In the event of a loss, the amount of insurance available might not be adequate to cover property damage and other expenses incurred. Uninsured losses and other expenses, to the extent not recovered from customers, would be borne by the Company and could have a material effect on the Company's financial condition and results of operations.

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

10. FAIR VALUE MEASUREMENTS

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

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

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

NOTES (continued)
Alabama Power Company 2013 Annual Report

As of December 31, 2013, assets and liabilities measured at fair value on a recurring basis during the period, together with the level of the fair value hierarchy in which they fall, were as follows:

	Fair Value Measurements Using			
As of December 31, 2013:	Quoted Prices in Active Markets for Identical Assets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)	Total
	(in millions)			
Assets:				
Energy-related derivatives	$—	$7	$—	$7
Nuclear decommissioning trusts:[a]				
Domestic equity	392	74	—	466
Foreign equity	35	65	—	100
U.S. Treasury and government agency securities	—	24	—	24
Corporate bonds	—	89	—	89
Mortgage and asset backed securities	—	18	—	18
Other investments	—	13	3	16
Cash equivalents	236	—	—	236
Total	$663	$290	$3	$956
Liabilities:				
Energy-related derivatives	$—	$8	$—	$8

(a) Excludes receivables related to investment income, pending investment sales, and payables related to pending investment purchases. See Note 1 under "Nuclear Decommissioning" for additional information.

As of December 31, 2012, assets and liabilities measured at fair value on a recurring basis during the period, together with the level of the fair value hierarchy in which they fall, were as follows:

	Fair Value Measurements Using			
As of December 31, 2012:	Quoted Prices in Active Markets for Identical Assets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)	Total
	(in millions)			
Assets:				
Energy-related derivatives	$—	$5	$—	$5
Nuclear decommissioning trusts:[a]				
Domestic equity	291	64	—	355
Foreign equity	28	55	—	83
U.S. Treasury and government agency securities	—	29	—	29
Corporate bonds	—	101	—	101
Mortgage and asset backed securities	—	26	—	26
Other investments	—	10	—	10
Total	$319	$290	$—	$609
Liabilities:				

Energy-related derivatives	$—	$18	$—	$18

(a) Excludes receivables related to investment income, pending investment sales, and payables related to pending investment purchases.

NOTES (continued)
Alabama Power Company 2013 Annual Report

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 financial products valued using the market approach. Inputs for interest rate derivatives include LIBOR interest rates, interest rate futures contracts, and occasionally implied volatility of interest rate options. See Note 11 for additional information on how these derivatives are used.
For fair value measurements of investments within the nuclear decommissioning trusts, specifically the fixed income assets using significant other observable inputs and unobservable inputs, the primary valuation technique used is the market approach. External pricing vendors are designated for each of the asset classes in the nuclear decommissioning trusts with each security discriminately assigned a primary pricing source, based on similar characteristics. Other 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 these assets using various inputs and techniques depending on the nature of the underlying investments. The fair value of partnerships is determined by aggregating the value of the underlying assets.
A market price secured from the primary source vendor is evaluated by management in its valuation of the assets within the trusts. As a general approach, 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' judgment are also obtained when available.
As of December 31, 2013 and 2012, the fair value measurements of investments calculated at net asset value per share (or its equivalent), as well as the nature and risks of those investments, were as follows:

	Fair Value	Unfunded Commitments	Redemption Frequency	Redemption Notice Period
As of December 31, 2013:	(in millions)			
Nuclear decommissioning trusts:				
Equity-commingled funds	$65	None	Daily/Monthly	Daily/7 Days
Trust-owned life insurance	110	None	Daily	15 days
Cash equivalents:				
Money market funds	236	None	Daily	Not applicable
As of December 31, 2012:				
Nuclear decommissioning trusts:				
Equity-commingled funds	$55	None	Daily/Monthly	Daily/7 days
Trust-owned life insurance	96	None	Daily	15 days

The nuclear decommissioning trust includes investments in TOLI. The taxable nuclear decommissioning trust invests in the TOLI in order to minimize the impact of taxes on the portfolio and can draw on the value of the TOLI through death proceeds, loans against the cash surrender value, and/or the cash surrender value, subject to legal restrictions. The amounts reported in the table above reflect the fair value of investments the insurer has made in relation to the TOLI agreements. The nuclear decommissioning trust does not own the underlying investments, but the fair value of the investments approximates the cash surrender value of the TOLI policies. The investments made by the insurer are in commingled funds. The commingled funds primarily include investments in domestic and international equity securities and predominantly high-quality fixed income securities. These fixed income securities may include U.S. Treasury and government agency fixed income securities, non-U.S. government and agency fixed income securities, domestic and foreign corporate fixed income securities, and, to some degree, mortgage and asset backed securities. The passively managed funds seek to replicate the performance of a related index. The actively managed funds seek to exceed the performance of a related index through security analysis and selection.

The money market funds are short-term investments of excess funds in various money market mutual funds, which are portfolios of short-term debt securities. The money market funds are regulated by the SEC and typically receive the highest rating from credit rating agencies. Regulatory and rating agency requirements for money market funds include minimum credit ratings and maximum maturities for individual securities and a maximum weighted average portfolio maturity. Redemptions are available on a same day basis, up to the full amount of the Company's investment in the money market funds.

NOTES (continued)
Alabama Power Company 2013 Annual Report

As of December 31, 2013 and 2012, other financial instruments for which the carrying amount did not equal fair value were as follows:

	Carrying Amount (in millions)	Fair Value
Long-term debt:		
2013	$6,228	$6,534
2012	$6,179	$6,899

The fair values are determined using Level 2 measurements and are based on quoted market prices for the same or similar issues or on the current rates offered to the Company.

11. DERIVATIVES

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

Energy-Related Derivatives

The Company enters into energy-related derivatives to hedge exposures to electricity, gas, and other fuel price changes. However, due to cost-based rate regulations and other various cost recovery mechanisms, the Company has limited exposure to market volatility in commodity fuel prices and prices of electricity. The Company manages fuel-hedging programs, implemented per the guidelines of the Alabama PSC, through the use of financial derivative contracts, which is expected to continue to mitigate price volatility.

To mitigate residual risks relative to movements in electricity prices, the Company may enter into physical fixed-price contracts for the purchase and sale of electricity through the wholesale electricity market. To mitigate residual risks relative to movements in gas prices, the Company may enter into fixed-price contracts for natural gas purchases; however, a significant portion of contracts are priced at market.

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

- Regulatory Hedges – Energy-related derivative contracts which are designated as regulatory hedges relate primarily to the Company's fuel-hedging programs, where gains and losses are initially recorded as regulatory liabilities and assets, respectively, and then are included in fuel expense as the underlying fuel is used in operations and ultimately recovered through the energy cost recovery clause.
- Cash Flow Hedges – Gains and losses on energy-related derivatives designated as cash flow hedges which are mainly used to hedge anticipated purchases and sales and 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.

NOTES (continued)
Alabama Power Company 2013 Annual Report

At December 31, 2013, the net volume of energy-related derivative contracts for natural gas positions for the Company, together with the longest hedge date over which it is hedging its exposure to the variability in future cash flows for forecasted transactions and the longest date for derivatives not designated as hedges, were as follows:

Net Purchased mmBtu* (in millions)	Longest Hedge Date	Longest Non-Hedge Date
69	2017	—

* million British thermal units (mmBtu)

For cash flow hedges, the amounts expected to be reclassified from accumulated OCI to revenue and fuel expense for the 12-month period ending December 31, 2014 are immaterial.

Interest Rate Derivatives

The Company may also enter into interest rate derivatives to hedge exposure to changes in interest rates. Derivatives related to existing variable rate securities or forecasted transactions are accounted for as cash flow hedges where the effective portion of the derivatives' fair value gains or losses is recorded in OCI and is reclassified into earnings at the same time the hedged transactions affect earnings. The derivatives employed as hedging instruments are structured to minimize ineffectiveness, which is recorded directly to earnings.

At December 31, 2013, there were no interest rate derivatives outstanding.

The estimated pre-tax losses that will be reclassified from accumulated OCI to interest expense for the 12-month period ending December 31, 2014 are $3 million. The Company has deferred gains and losses that are expected to be amortized into earnings through 2035.

Derivative Financial Statement Presentation and Amounts

At December 31, 2013 and 2012, the fair value of energy-related derivatives was reflected in the balance sheets as follows:

Derivative Category	Asset Derivatives Balance Sheet Location	2013	2012	Liability Derivatives Balance Sheet Location	2013	2012
		(in millions)			(in millions)	
Derivatives designated as hedging instruments for regulatory purposes						
Energy-related derivatives:	Other current assets	$5	$2	Liabilities from risk management activities	$3	$14
	Other deferred charges and assets	2	3	Other deferred credits and liabilities	5	4
Total derivatives designated as hedging instruments for regulatory purposes		$7	$5		$8	$18
Total		$7	$5		$8	$18

All derivative instruments are measured at fair value. See Note 10 for additional information.

Table of Contents Index to Financial Statements

NOTES (continued)
Alabama Power Company 2013 Annual Report

The derivative contracts of the Company 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 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 at December 31, 2013 and 2012 are presented in the following tables.

Fair Value					
Assets	2013	2012	Liabilities	2013	2012
	(in millions)			(in millions)	
Energy-related derivatives presented in the Balance Sheet [(a)]	$7	$5	Energy-related derivatives presented in the Balance Sheet [(a)]	$8	$18
Gross amounts not offset in the Balance Sheet [(b)]	(5)	(4)	Gross amounts not offset in the Balance Sheet [(b)]	(5)	(4)
Net-energy related derivative assets	$2	$1	Net-energy related derivative liabilities	$3	$14

(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, 2013 and 2012, the pre-tax effect of unrealized derivative gains (losses) arising from energy-related derivative instruments designated as regulatory hedging instruments and deferred on the balance sheets was as follows:

Derivative Category	Unrealized Losses Balance Sheet Location	2013	2012	Unrealized Gains Balance Sheet Location	2013	2012
		(in millions)			(in millions)	
Energy-related derivatives:	Other regulatory assets, current	$(3)	$(14)	Other current liabilities	$5	$2
	Other regulatory assets, deferred	(5)	(4)	Other regulatory liabilities, deferred	2	3
Total energy-related derivative gains (losses)		$(8)	$(18)		$7	$5

For the years ended December 31, 2013, 2012, and 2011, the pre-tax effect of interest rate derivatives designated as cash flow hedging instruments on the statements of income was as follows:

Derivatives in Cash Flow Hedging Relationships	Gain (Loss) Recognized in OCI on Derivative (Effective Portion)			Gain (Loss) Reclassified from Accumulated OCI into Income (Effective Portion)			
					Amount		
Derivative Category	2013	2012	2011	Statements of Income Location	2013	2012	2011
	(in millions)				(in millions)		
Interest rate derivatives	$—	$(18)	$(14)	Interest expense, net of amounts capitalized	$(3)	$(3)	$3

There was no material ineffectiveness recorded in earnings for any period presented.
For the years ended December 31, 2013, 2012, and 2011, the pre-tax effect of energy-related derivatives not designated as hedging instruments on the statements of income was not material.

Contingent Features

The Company does not have any credit arrangements that would require material changes in payment schedules or terminations as a result of a credit rating downgrade. There are certain derivatives that could require collateral, but not accelerated payment, in the event of various credit rating changes of certain affiliated companies. At December 31, 2013, the fair value of derivative liabilities with contingent features was $1 million.

NOTES (continued)
Alabama Power Company 2013 Annual Report

The Company's collateral posted with its derivative counterparties at December 31, 2013 was not material. However, because of the joint and several liability features underlying these derivatives, the maximum potential collateral requirements arising from the credit-risk-related contingent features, at a rating below BBB- and/or Baa3, were $9 million. 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.

Generally, collateral may be provided by a Southern Company guaranty, letter of credit, or cash. The Company participates in 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.

The Company is exposed to losses related to financial instruments in the event of counterparties' nonperformance. The Company only enters into agreements and material transactions with counterparties that have investment grade credit ratings by Moody's Investors Services, Inc. and Standard and Poor's Ratings Services, a division of The McGraw Hill Companies, Inc. or with counterparties who have posted collateral to cover potential credit exposure. The Company has also established risk management policies and controls to determine and monitor the creditworthiness of counterparties in order to mitigate the Company's exposure to counterparty credit risk. Therefore, the Company does not anticipate a material adverse effect on the financial statements as a result of counterparty nonperformance.

Table of Contents Index to Financial Statements

NOTES (continued)
Alabama Power Company 2013 Annual Report

12. QUARTERLY FINANCIAL INFORMATION (UNAUDITED)

Summarized quarterly financial information for 2013 and 2012 is as follows:

Quarter Ended	Operating Revenues	Operating Income	Net Income After Dividends on Preferred and Preference Stock
	(in millions)		
March 2013	$1,308	$307	$141
June 2013	1,392	357	173
September 2013	1,604	500	258
December 2013	1,314	312	140
March 2012	$1,216	$291	$126
June 2012	1,377	390	185
September 2012	1,637	544	280
December 2012	1,290	271	113

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

SELECTED FINANCIAL AND OPERATING DATA 2009-2013
Alabama Power Company 2013 Annual Report

	2013	2012	2011	2010	2009
Operating Revenues (in millions)	$5,618	$5,520	$5,702	$5,976	$5,529
Net Income After Dividends on Preferred and Preference Stock (in millions)	$712	$704	$708	$707	$670
Cash Dividends on Common Stock (in millions)	$644	$684	$774	$586	$523
Return on Average Common Equity (percent)	13.07	13.10	13.19	13.31	13.27
Total Assets (in millions)	$19,251	$18,712	$18,477	$17,994	$17,524
Gross Property Additions (in millions)	$1,204	$940	$1,016	$956	$1,323
Capitalization (in millions):					
Common stock equity	$5,502	$5,398	$5,342	$5,393	$5,237
Preference stock	343	343	343	343	343
Redeemable preferred stock	342	342	342	342	342
Long-term debt	6,233	5,929	5,632	5,987	6,082
Total (excluding amounts due within one year)	$12,420	$12,012	$11,659	$12,065	$12,004
Capitalization Ratios (percent):					
Common stock equity	44.3	44.9	45.8	44.7	43.6
Preference stock	2.8	2.9	2.9	2.9	2.9
Redeemable preferred stock	2.7	2.8	2.9	2.8	2.8
Long-term debt	50.2	49.4	48.4	49.6	50.7
Total (excluding amounts due within one year)	100.0	100.0	100.0	100.0	100.0
Customers (year-end):					
Residential	1,241,998	1,237,730	1,231,574	1,235,128	1,229,134
Commercial	196,209	196,177	196,270	197,336	198,642
Industrial	5,851	5,839	5,844	5,770	5,912
Other	751	748	746	782	780
Total	1,444,809	1,440,494	1,434,434	1,439,016	1,434,468
Employees (year-end)	6,896	6,778	6,632	6,552	6,842

SELECTED FINANCIAL AND OPERATING DATA 2009-2013 (continued)
Alabama Power Company 2013 Annual Report

	2013	2012	2011	2010	2009
Operating Revenues (in millions):					
Residential	$2,079	$2,068	$2,144	$2,283	$1,962
Commercial	1,477	1,491	1,495	1,535	1,430
Industrial	1,369	1,346	1,306	1,231	1,080
Other	27	28	27	27	25
Total retail	4,952	4,933	4,972	5,076	4,497
Wholesale — non-affiliates	248	277	287	465	620
Wholesale — affiliates	212	111	244	236	237
Total revenues from sales of electricity	5,412	5,321	5,503	5,777	5,354
Other revenues	206	199	199	199	175
Total	$5,618	$5,520	$5,702	$5,976	$5,529
Kilowatt-Hour Sales (in millions):					
Residential	17,920	17,612	18,650	20,417	18,071
Commercial	13,892	13,963	14,173	14,719	14,186
Industrial	22,904	22,158	21,666	20,622	18,555
Other	211	214	214	216	218
Total retail	54,927	53,947	54,703	55,974	51,030
Wholesale — non-affiliates	3,711	4,196	4,330	8,655	14,317
Wholesale — affiliates	7,672	4,279	7,211	6,074	6,473
Total	66,310	62,422	66,244	70,703	71,820
Average Revenue Per Kilowatt-Hour (cents):					
Residential	11.60	11.74	11.50	11.18	10.86
Commercial	10.63	10.68	10.55	10.43	10.08
Industrial	5.98	6.07	6.03	5.97	5.82
Total retail	9.02	9.14	9.09	9.07	8.81
Wholesale	4.04	4.58	4.60	4.76	4.12
Total sales	8.16	8.52	8.31	8.17	7.45
Residential Average Annual Kilowatt-Hour Use Per Customer	14,451	14,252	15,138	16,570	14,716
Residential Average Annual Revenue Per Customer	$1,676	$1,674	$1,740	$1,853	$1,597
Plant Nameplate Capacity Ratings (year-end) (megawatts)	12,222	12,222	12,222	12,222	12,222
Maximum Peak-Hour Demand (megawatts):					
Winter	9,347	10,285	11,553	11,349	10,701
Summer	10,692	11,096	11,500	11,488	10,870
Annual Load Factor (percent)	64.9	61.3	60.6	62.6	59.8
Plant Availability (percent)*:					
Fossil-steam	87.3	88.6	88.7	92.9	88.5
Nuclear	90.7	94.5	94.7	88.4	93.3
Source of Energy Supply (percent):					
Coal	50.0	48.2	52.5	56.6	53.4
Nuclear	20.3	22.6	20.8	17.7	18.6

Hydro	8.1	4.1	4.6	5.0	7.9
Gas	15.7	16.8	15.3	14.0	11.8
Purchased power —					
From non-affiliates	2.9	2.0	0.9	1.6	2.0
From affiliates	3.0	6.3	5.9	5.1	6.3
Total	100.0	100.0	100.0	100.0	100.0

* Beginning in 2012, plant availability is calculated as a weighted equivalent availability.

Table of Contents Index to Financial Statements

GEORGIA POWER COMPANY
FINANCIAL SECTION

Table of Contents Index to Financial Statements

MANAGEMENT'S REPORT ON INTERNAL CONTROL OVER FINANCIAL REPORTING
Georgia Power Company 2013 Annual Report

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

Under management's supervision, an evaluation of the design and effectiveness of the Company's internal control over financial reporting was conducted based on the framework in Internal Control—Integrated Framework (1992) issued by the Committee of Sponsoring Organizations of the Treadway Commission. Based on this evaluation, management concluded that the Company's internal control over financial reporting was effective as of December 31, 2013.

/s/ W. Paul Bowers
W. Paul Bowers
President and Chief Executive Officer

/s/ W. Ron Hinson
W. Ron Hinson
Executive Vice President, Chief Financial Officer, and Treasurer

February 27, 2014

Table of Contents Index to Financial Statements

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM
To the Board of Directors of
Georgia Power Company

We have audited the accompanying balance sheets and statements of capitalization of Georgia Power Company (the Company) (a wholly owned subsidiary of The Southern Company) as of December 31, 2013 and 2012, and the related statements of income, comprehensive income, common stockholder's equity, and cash flows for each of the three years in the period ended December 31, 2013. These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements based on our audits.

We conducted our audits in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. The Company is not required to have, nor were we engaged to perform, an audit of its internal control over financial reporting. Our audits included consideration of internal control over financial reporting as a basis for designing audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the Company's internal control over financial reporting. Accordingly, we express no such opinion. An audit also includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

In our opinion, such financial statements (pages II-226 to II-276) present fairly, in all material respects, the financial position of Georgia Power Company as of December 31, 2013 and 2012, and the results of its operations and its cash flows for each of the three years in the period ended December 31, 2013, in conformity with accounting principles generally accepted in the United States of America.

/s/ Deloitte & Touche LLP
Atlanta, Georgia
February 27, 2014

MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS
Georgia Power Company 2013 Annual Report
OVERVIEW
Business Activities
Georgia Power Company (the Company) operates as a vertically integrated utility providing electricity to retail customers within its traditional service area located within the State of Georgia and to wholesale customers in the Southeast.
Many factors affect the opportunities, challenges, and risks of the Company's business of selling electricity. These factors include the ability to maintain a constructive regulatory environment, to maintain and grow energy sales given economic conditions, 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, and fuel. In addition, the Company is currently constructing two new nuclear generating units at Plant Vogtle (Plant Vogtle Units 3 and 4) to increase its generation diversity and meet future supply needs. Appropriately balancing required costs and capital expenditures with customer prices will continue to challenge the Company for the foreseeable future.
On December 17, 2013, the Georgia Public Service Commission (PSC) approved an Alternate Rate Plan for the years 2014 through 2016 (2013 ARP), including base rate increases of approximately $110 million, $187 million, and $170 million effective January 1, 2014, 2015, and 2016, respectively. The Company is scheduled to file its next base rate case by July 1, 2016. See FUTURE EARNINGS POTENTIAL – "PSC Matters – Rate Plans" herein for additional information.
Key Performance Indicators
The Company continues to focus on several key performance indicators. These indicators include customer satisfaction, plant availability, system reliability, the execution of major construction projects, and net income after dividends on preferred and preference stock. The Company's financial success is directly tied to customer satisfaction. Key elements of ensuring customer satisfaction include outstanding service, high reliability, and competitive prices. Management uses customer satisfaction surveys and reliability indicators to evaluate the Company's results.
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 2013 Peak Season EFOR did not meet the target due to an explosion at Plant Bowen in April 2013. See FUTURE EARNINGS POTENTIAL – "Other Matters" herein for additional information. Transmission and distribution system reliability performance is measured by the frequency and duration of outages, with performance targets set based on historical performance. The 2013 performance was better than the target for these reliability measures.
Net income after dividends on preferred and preference stock is the primary measure of the Company's financial performance. The Company's 2013 results compared to its targets for some of these key indicators are reflected in the following chart:

Key Performance Indicator	2013 Target Performance	2013 Actual Performance
Customer Satisfaction	Top quartile in customer surveys	Top quartile
Peak Season EFOR — fossil/hydro	5.86% or less	9.55%
Net Income After Dividends on Preferred and Preference Stock	$1.19 billion	$1.17 billion

See RESULTS OF OPERATIONS herein for additional information on the Company's financial performance. The 2013 net income after dividends on preferred and preference stock did not meet the target due to significantly milder than normal weather.
Earnings
The Company's 2013 net income after dividends on preferred and preference stock totaled $1.2 billion, representing a $6 million, or 0.5%, increase over the previous year. The increase was due primarily to an increase related to retail

revenue rate effects, partially offset by milder weather in 2013, an increase in depreciation and amortization, and higher income taxes.

The Company's 2012 net income after dividends on preferred and preference stock totaled $1.2 billion representing a $23 million, or 2.0%, increase over the previous year. The increase was due primarily to lower operations and maintenance expenses resulting from cost containment efforts in 2012 and retail revenue rate effects as authorized by the Georgia PSC under the Alternate Rate Plan for the years 2011 through 2013 (2010 ARP). These increases were partially offset by lower operating revenues as a result of

Table of Contents Index to Financial Statements

milder weather in 2012 and a decrease in customer usage, lower allowance for funds used during construction (AFUDC) equity, higher depreciation and amortization, primarily as a result of completing construction of Plant McDonough-Atkinson Units 4 and 5, higher income taxes, and higher interest expense reflecting a 2011 settlement of tax litigation with the Georgia Department of Revenue (DOR).

RESULTS OF OPERATIONS

A condensed income statement for the Company follows:

	Amount	Increase (Decrease) from Prior Year	
	2013	2013	2012
	(in millions)		
Operating revenues	$8,274	$276	$(802)
Fuel	2,307	256	(738)
Purchased power	884	(97)	(122)
Other operations and maintenance	1,654	10	(133)
Depreciation and amortization	807	62	30
Taxes other than income taxes	382	8	5
Total operating expenses	6,034	239	(958)
Operating income	2,240	37	156
Allowance for equity funds used during construction	30	(23)	(43)
Interest expense, net of amounts capitalized	361	(5)	23
Other income (expense), net	5	22	(4)
Income taxes	723	35	63
Net income	1,191	6	23
Dividends on preferred and preference stock	17	—	—
Net income after dividends on preferred and preference stock	$1,174	$6	$23

Table of Contents Index to Financial Statements

MANAGEMENT'S DISCUSSION AND ANALYSIS (continued)
Georgia Power Company 2013 Annual Report

Operating Revenues
Operating revenues for 2013 were $8.3 billion, reflecting a $276 million increase from 2012. Details of operating revenues were as follows:

	Amount	
	2013	2012
	(in millions)	
Retail — prior year	$7,362	$8,099
Estimated change resulting from —		
Rates and pricing	137	166
Sales growth (decline)	(5)	(26)
Weather	(61)	(147)
Fuel cost recovery	187	(730)
Retail — current year	7,620	7,362
Wholesale revenues —		
Non-affiliates	281	281
Affiliates	20	20
Total wholesale revenues	301	301
Other operating revenues	353	335
Total operating revenues	$8,274	$7,998
Percent change	3.5%	(9.1)%

Retail base revenues of $4.9 billion in 2013 increased $71 million, or 1.5%, compared to 2012 primarily due to base tariff increases effective April 1, 2012 and January 1, 2013, as approved by the Georgia PSC, related to placing new generating units at Plant McDonough-Atkinson in service and collecting financing costs related to the construction of Plant Vogtle Units 3 and 4 through the Nuclear Construction Cost Recovery (NCCR) tariff, as well as higher contributions from market-driven rates from commercial and industrial customers. The increase was partially offset by milder weather in 2013 as compared to 2012. In 2013, residential base revenues decreased $3 million, or 0.1%, commercial base revenues increased $43 million, or 2.2%, and industrial base revenues increased $28 million, or 4.4%, compared to 2012. Residential usage continues to be impacted by economic uncertainty, modest economic growth, and energy efficiency efforts.

Retail base revenues of $4.8 billion in 2012 were flat compared to 2011 primarily due to milder weather in 2012, decreased customer usage, and lower contributions from market-driven rates from commercial and industrial customers, offset by base tariff increases effective April 1, 2012 related to placing Plant McDonough-Atkinson Units 4 and 5 in service, collecting financing costs related to the construction of Plant Vogtle Units 3 and 4 through the NCCR tariff, and demand-side management programs effective January 1, 2012, as approved by the Georgia PSC, as well as the rate pricing effect of decreased customer usage. In 2012, residential base revenues increased $17 million, or 0.8%, commercial base revenues increased $11 million, or 0.6%, and industrial base revenues decreased $36 million, or 5.4%, compared to 2011. Economic uncertainty impacted residential, commercial, and industrial base revenues.

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

Electric rates include provisions to adjust billings for fluctuations in fuel costs, including the energy component of purchased power costs. Under these fuel cost recovery provisions, fuel revenues generally equal fuel expenses and do not affect net income. The Company further lowered fuel rates effective January 1, 2013. See FUTURE EARNINGS POTENTIAL – "PSC Matters – Fuel Cost Recovery" herein for additional information.

MANAGEMENT'S DISCUSSION AND ANALYSIS (continued)
Georgia Power Company 2013 Annual Report

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

	2013	2012	2011
	(in millions)		
Capacity and other	$174	$177	$177
Energy	107	104	164
Total non-affiliated	$281	$281	$341

Wholesale revenues from sales to non-affiliates consist of power purchase agreements (PPA) and short-term opportunity sales. Capacity revenues reflect the recovery of fixed costs and a return on investment. Wholesale revenues from sales to non-affiliates will vary depending on fuel prices, the market prices of wholesale energy compared to the cost of the Company's and the Southern Company system's generation, demand for energy within the Southern Company system's service territory, and the availability of the Southern Company system's generation. Increases and decreases in energy revenues that are driven by fuel prices are accompanied by an increase or decrease in fuel costs and do not have a significant impact on net income. Short-term opportunity sales are made at market-based rates that generally provide a margin above the Company's variable cost of energy.

Revenues from other non-affiliated sales were flat in 2013 and decreased $60 million, or 17.6%, in 2012. The decrease in 2012 was primarily due to a 24.9% decrease in kilowatt-hour (KWH) sales due to lower demand resulting from milder weather and the availability of market energy at a lower cost than Company-owned generation.

Wholesale revenues from sales to affiliated companies will vary depending on demand and the availability and cost of generating resources at each company. These affiliate sales are made in accordance with the Intercompany Interchange Contract (IIC), as approved by the Federal Energy Regulatory Commission (FERC). These transactions do not have a significant impact on earnings since this energy is generally sold at marginal cost. In 2013, wholesale revenues from sales to affiliates remained flat and decreased $12 million in 2012 due to a decrease of 4.2% in KWH sales as a result of lower demand because the market cost of available energy was lower than the cost of Company-owned generation. In 2012, lower demand also resulted from the milder weather.

Other operating revenues increased $18 million, or 5.4%, in 2013 from the prior year primarily due to higher revenues from transmission, pole attachments, and outdoor lighting. Other operating revenues increased $7 million, or 2.1%, in 2012 from the prior year primarily due to higher revenues from outdoor lighting and pole attachments.

Table of Contents Index to Financial Statements

MANAGEMENT'S DISCUSSION AND ANALYSIS (continued)
Georgia Power Company 2013 Annual Report

Energy Sales

Changes in revenues are influenced heavily by the change in the volume of energy sold from year to year. KWH sales for 2013 and the percent change by year were as follows:

	Total KWHs 2013 (in billions)	Total KWH Percent Change 2013	Total KWH Percent Change 2012	Weather-Adjusted Percent Change 2013*	Weather-Adjusted Percent Change 2012
Residential	25.5	(1.0)%	(5.4)%	0.1%	0.3%
Commercial	32.0	(0.9)	(1.9)	(0.2)	(0.6)
Industrial	23.1	—	(1.8)	0.7	(1.2)
Other	0.6	(1.8)	(2.5)	(1.8)	(2.0)
Total retail	81.2	(0.7)	(3.0)	0.1%	(0.5)%
Wholesale					
Non-affiliates	3.0	3.3	(24.9)		
Affiliates	0.5	(17.4)	(4.2)		
Total wholesale	3.5	(0.2)	(22.0)		
Total energy sales	84.7	(0.7)%	(4.0)%		

* In the first quarter 2012, the Company began using new actual advanced meter data to compute unbilled revenues. The weather-adjusted KWH sales variances shown above reflect an adjustment to the estimated allocation of the Company's unbilled January 2012 KWH sales among customer classes that is consistent with the actual allocation in 2013. Without this adjustment, 2013 weather-adjusted residential KWH sales decreased 0.4% as compared to 2012 while weather-adjusted commercial KWH sales increased 0.2% as compared to 2012.

Changes in retail energy sales are comprised of changes in electricity usage by customers, changes in weather, and changes in the number of customers.

In 2013, KWH sales for residential and commercial customer classes decreased compared to 2012 primarily due to milder weather in 2013. Industrial sales were flat in 2013 compared to 2012. Increased demand in the paper, textiles, and stone, clay, and glass sectors were the main contributors to the increase in weather-adjusted industrial sales.

In 2012, KWH sales for all customer classes decreased compared to 2011 primarily due to milder weather in 2012. Economic uncertainty continues to impact sales for all customer classes as well; however, an increase of approximately 15,000 new residential customers in 2012 contributed to a slight increase in weather-adjusted residential KWH sales.

See "Operating Revenues" above for a discussion of significant changes in wholesale sales to non-affiliates and affiliated companies.

Fuel and Purchased Power Expenses

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

MANAGEMENT'S DISCUSSION AND ANALYSIS (continued)
Georgia Power Company 2013 Annual Report

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

	2013	2012	2011
Total generation (billions of KWHs)	66.8	59.8	65.5
Total purchased power (billions of KWHs)	21.4	28.7	26.8
Sources of generation (percent) -			
Coal	35	39	62
Nuclear	23	27	23
Gas	39	33	13
Hydro	3	1	2
Cost of fuel, generated (cents per net KWH) -			
Coal	4.92	4.63	4.70
Nuclear	0.91	0.87	0.78
Gas	3.33	3.02	4.92
Average cost of fuel, generated (cents per net KWH)	3.32	3.07	3.80
Average cost of purchased power (cents per net KWH) *	4.83	4.24	5.38

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

Fuel and purchased power expenses were $3.2 billion in 2013, an increase of $159 million, or 5.2%, compared to 2012. The increase was primarily due to a $284 million increase in the average cost of fuel and purchased power primarily due to higher natural gas prices and a $185 million increase due to an increase in the volume of KWHs generated, partially offset by a $310 million decrease due to a decrease in the volume of KWHs purchased, as the cost of Company-owned generation was lower than the market cost of available energy.

Fuel and purchased power expenses were $3.0 billion in 2012, a decrease of $860 million, or 22.1%, compared to 2011. The decrease was primarily due to a $703 million decrease in the average cost of fuel and purchased power primarily due to lower natural gas prices and a $259 million decrease due to a decrease in the volume of KWHs generated as a result of lower customer demand from milder weather in 2012. These decreases were partially offset by a $102 million increase due to an increase in the volume of KWHs purchased, as the market cost of available energy was lower than the additional Company-owned generation available.

Fuel and purchased power energy transactions do not have a significant impact on earnings since these fuel expenses are generally offset by fuel revenues through the Company's fuel cost recovery mechanism. See FUTURE EARNINGS POTENTIAL – "PSC Matters – Fuel Cost Recovery" herein for additional information.

Fuel

Fuel expense was $2.3 billion in 2013, an increase of $256 million, or 12.5%, compared to 2012. The increase was primarily due to a 9.9% increase in the volume of KWHs generated as a result of higher prices for purchased power and an 8.1% increase in the average cost of fuel per KWH generated for all types of fuel generation, partially offset by a 191.0% increase in the volume of KWHs generated by hydro facilities resulting from greater rainfall. Fuel expense was $2.1 billion in 2012, a decrease of $738 million, or 26.5%, compared to 2011. The decrease was primarily due to an 8.4% decrease in KWHs generated as a result of lower demand and a 19.2% decrease in the average cost of fuel per KWH generated primarily due to lower natural gas prices. In addition, the Company's fuel mix for generation changed from 62% coal and 13% natural gas in 2011 to 39% coal and 33% natural gas in 2012 primarily due to the completion of the Plant McDonough-Atkinson combined cycle units.

Purchased Power - Non-Affiliates

Purchased power expense from non-affiliates was $224 million in 2013, a decrease of $91 million, or 28.9%, compared to 2012. The decrease was primarily due to a 52.0% decrease in the volume of KWHs purchased as the cost of Company-owned generation was lower than the market cost of available energy, partially offset by an increase of 41.5% in the average cost per KWH purchased primarily due to higher fuel prices. Purchased power expense from non-affiliates was $315 million in 2012, a decrease of $75 million, or 19.2%, compared to 2011. The decrease was due to a 23.8% decrease in the average cost per KWH purchased primarily due to lower natural gas prices, partially offset by a 7.0% increase in the volume of KWHs purchased, as the market cost of available energy was lower than the cost of additional Company-owned generation.

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

Purchased Power - Affiliates

Purchased power expense from affiliates was $660 million in 2013, a decrease of $6 million, or 0.9%, compared to 2012. The decrease was primarily due to an 18.4% decrease in the volume of KWHs purchased as the Company's units generally dispatched at a lower cost than other Southern Company system resources, partially offset by a 12.6% increase in the average cost per KWH purchased reflecting higher fuel prices. Purchased power expense from affiliates was $666 million in 2012, a decrease of $47 million, or 6.6%, compared to 2011. The decrease was primarily due to a 20.2% decrease in the average cost per KWH purchased, reflecting lower natural gas prices, partially offset by a 7.1% increase in the volume of KWHs purchased as the cost of the available energy was lower than the cost of Company-owned generation available.

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

Other Operations and Maintenance Expenses

In 2013, other operations and maintenance expenses increased $10 million, or 0.6%, compared to 2012. The increase was primarily due to an increase of $33 million in pension and other employee benefit-related expenses and $13 million in transmission system load expense resulting from billing adjustments with integrated transmission system owners, partially offset by a decrease of $38 million in fossil generating expenses due to cost containment and outage timing to offset milder weather in 2013 as compared to 2012 and the effect of economic uncertainty.

In 2012, other operations and maintenance expenses decreased $133 million, or 7.5%, compared to 2011. The decrease was primarily due to the timing of planned generation outages and decreases in transmission and distribution maintenance as a result of cost containment efforts to offset the effects of milder weather in 2012 and a decrease in uncollectible account expense of $24 million, as a result of lower revenues, a slightly improving economy, and a change in the customer deposit policy, partially offset by a net increase in pension and other employee benefit-related expenses of $14 million.

Depreciation and Amortization

Depreciation and amortization increased $62 million, or 8.3%, in 2013 compared to 2012. The increase was primarily due to an increase of $64 million in depreciation on additional plant in service due to the completion of Plant McDonough-Atkinson Units 5 and 6 in April 2012 and October 2012, respectively, and depreciation and amortization resulting from certain coal unit retirement decisions (with respect to the portion of such units dedicated to wholesale service). The increase was partially offset by a net reduction in amortization primarily related to amortization of the regulatory liability previously established for state income tax credits, as authorized by the Georgia PSC. See Note 1 to the financial statements under "Regulatory Assets and Liabilities" for additional information on the state income tax credits regulatory liability.

Depreciation and amortization increased $30 million, or 4.2%, in 2012 compared to 2011. The increase was primarily due to an increase of $50 million in depreciation on additional plant in service primarily related to new generation at Plant McDonough-Atkinson Units 4 and 5, partially offset by $27 million in amortization of the regulatory liability for state income tax credits as authorized by the Georgia PSC. See Note 1 to the financial statements under "Regulatory Assets and Liabilities" for additional information.

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

Taxes Other Than Income Taxes

In 2013, taxes other than income taxes increased $8 million, or 2.1%, compared to 2012. The increase was primarily due to an increase in property taxes.

In 2012, taxes other than income taxes increased $5 million, or 1.4%, compared to 2011. The increase was primarily due to a $20 million increase in property taxes, partially offset by a $12 million decrease in municipal franchise fees resulting from lower retail revenues in 2012.

Allowance for Funds Used During Construction Equity

AFUDC equity decreased $23 million, or 43.4%, in 2013 compared to the prior year primarily due to the completion of Plant McDonough-Atkinson Units 5 and 6 in April 2012 and October 2012, respectively.

MANAGEMENT'S DISCUSSION AND ANALYSIS (continued)
Georgia Power Company 2013 Annual Report

AFUDC equity decreased $43 million, or 44.8%, in 2012 compared to the prior year primarily due to the completion of Plant McDonough-Atkinson Units 4, 5, and 6 in December 2011, April 2012, and October 2012, respectively.

Interest Expense, Net of Amounts Capitalized

In 2013, interest expense, net of amounts capitalized decreased $5 million, or 1.4%, from the prior year. The decrease was primarily due to a $21 million decrease in interest on long-term debt as a result of refinancing activity, partially offset by an $8 million decrease in AFUDC debt primarily due to the completion of Plant McDonough Units 5 and 6 discussed previously and a $9 million increase resulting from the conclusion of certain state and federal income tax audits that reduced interest expense in 2012.

In 2012, interest expense, net of amounts capitalized increased $23 million, or 6.7%, from the prior year primarily due to a $23 million reduction in interest expense in 2011 resulting from the settlement of litigation with the Georgia DOR, a $16 million decrease in AFUDC debt in 2012 primarily due to the completion of Plant McDonough-Atkinson Units 4 and 5 discussed previously, and a net increase of $18 million in interest expense related to outstanding senior notes. The increase was partially offset by reductions in expense related to pollution control revenue bonds, the redemption of all trust preferred securities in September 2011, and the conclusion of certain state and federal income tax audits in 2012 of $13 million, $9 million, and $9 million, respectively.

Other Income (Expense), net

In 2013, other income (expense), net increased $22 million, or 129.4%, from the prior year primarily due to an $8 million increase in wholesale operating fees and a $9 million decrease in donations.

In 2012, other income (expense), net decreased $4 million, or 30.8%, from the prior year. The decrease was not material.

Income Taxes

Income taxes increased $35 million, or 5.1%, in 2013 compared to the prior year primarily due to a decrease in state income tax credits, higher pre-tax earnings, and a decrease in non-taxable AFUDC equity, partially offset by a decrease in non-deductible book depreciation.

Income taxes increased $63 million, or 10.1%, in 2012 compared to the prior year primarily due to higher pre-tax earnings, an increase in non-deductible book depreciation, and a decrease in non-taxable AFUDC equity, partially offset by state income tax credits.

See "Allowance for Funds Used During Construction Equity" herein for additional information.

Effects of Inflation

The Company is subject to rate regulation that is generally based on the recovery of historical and projected costs. The effects of inflation can create an economic loss since the recovery of costs could be in dollars that have less purchasing power. Any adverse effect of inflation on the Company's results of operations has not been substantial in recent years.

FUTURE EARNINGS POTENTIAL

General

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

The results of operations for the past three years are not necessarily indicative of future earnings potential. The level of the Company's future earnings depends on numerous factors that affect the opportunities, challenges, and risks of the Company's business of selling electricity. These factors include the Company's ability to maintain a constructive regulatory environment that continues to allow for the timely recovery of prudently-incurred costs during a time of increasing costs and the successful completion of ongoing construction projects, including the construction of Plant Vogtle Units 3 and 4. Future earnings in the near term will depend, in part, upon maintaining energy sales which is subject to a number of factors. These factors include weather, competition, new energy contracts with other utilities, energy conservation practiced by customers, the price of electricity, the price elasticity of demand, and the rate of economic growth or decline in the Company's service territory. Changes in regional and global economic conditions impact sales for the Company, as the pace of the economic recovery remains uncertain. The timing and extent of the economic recovery will impact growth and may impact future earnings.

In 2013, the Company's generating capacity decreased 398 megawatts (MWs) due to the retirements of Plant Bowen Unit 6 on April 25, 2013, Plant Boulevard Units 2 and 3 on July 17, 2013, and Plant Branch Unit 2 on September 30, 2013. New generating capacity and retirements are approved by the Georgia PSC through the Integrated Resource Plan (IRP) process. See "PSC Matters – Integrated Resource Plans" herein and Note 3 to the financial statements under "Retail Regulatory Matters – Integrated Resource Plans" for additional information.

Environmental Matters

Compliance costs related to federal and state environmental statutes and regulations could affect earnings if such costs cannot continue to be fully recovered in rates on a timely basis. Environmental compliance spending over the next several years may differ materially from the amounts estimated. The timing, specific requirements, and estimated costs could change as environmental statutes and regulations are adopted or modified. The Company's Environmental Compliance Cost Recovery (ECCR) tariff allows for the recovery of capital and operations and maintenance costs related to environmental controls mandated by state and federal regulations. Further, higher costs that are recovered through regulated rates could contribute to reduced demand for electricity, which could negatively affect results of operations, cash flows, and financial condition. See Note 3 to the financial statements under "Environmental Matters" for additional information.

New Source Review Actions

As part of a nationwide enforcement initiative against the electric utility industry which began in 1999, the U.S. Environmental Protection Agency (EPA) brought civil enforcement actions in federal district court against the Company alleging violations of the New Source Review (NSR) provisions of the Clean Air Act at certain coal-fired electric generating units, including a unit co-owned by Gulf Power Company (Gulf Power). These civil actions seek penalties and injunctive relief, including orders requiring installation of the best available control technologies at the affected units. The case against the Company (including claims related to a unit co-owned by Gulf Power) has been administratively closed in the U.S. District Court for the Northern District of Georgia since 2001.

The Company believes it complied with applicable laws and regulations in effect at the time the work in question took place. The Clean Air Act authorizes maximum civil penalties of $25,000 to $37,500 per day, per violation, depending on the date of the alleged violation. An adverse outcome could require substantial capital expenditures that cannot be determined at this time and could possibly require payment of substantial penalties. Such expenditures could affect future results of operations, cash flows, and financial condition if such costs are not recovered through regulated rates. The ultimate outcome of this matter cannot be determined at this time.

Environmental Statutes and Regulations

General

The Company's operations are subject to extensive regulation by state and federal environmental agencies under a variety of statutes and regulations governing environmental media, including air, water, and land resources. Applicable statutes include the Clean Air Act; the Clean Water Act; the Comprehensive Environmental Response, Compensation, and Liability Act; the Resource Conservation and Recovery Act; the Toxic Substances Control Act; the Emergency Planning & Community Right-to-Know Act; the Endangered Species Act; 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 2013, the Company had invested approximately $4.3 billion in environmental capital retrofit projects to comply with these requirements, with annual totals of approximately $309 million, $152 million, and $113 million in 2013, 2012, and 2011, respectively. The Company expects that capital expenditures to comply with environmental statutes and regulations will total approximately $1.1 billion from 2014 through 2016, with annual totals of approximately $543 million, $366 million, and $202 million for 2014, 2015, and 2016, respectively.

The Company continues to monitor the development of the EPA's proposed water and coal combustion residuals rules and to evaluate compliance options. Based on its preliminary analysis and an assumption that coal combustion residuals will continue to be regulated as non-hazardous solid waste under the proposed rule, the Company does not anticipate that material compliance costs with respect to these proposed rules will be required during the period of 2014 through 2016. The ultimate capital expenditures and compliance costs with respect to these proposed rules, including additional expenditures required after 2016, will be dependent on the requirements of the final rules and regulations adopted by the EPA and the outcome of any legal challenges to these rules. See "Water Quality" and "Coal Combustion Residuals" herein for additional information.

The Company's ultimate environmental compliance strategy, including potential unit retirement and replacement decisions, and future environmental capital expenditures will be affected by the final requirements of new or revised environmental regulations and regulations relating to global climate change that are promulgated, including the proposed 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 Company's fuel mix. Compliance costs may arise from existing unit retirements, installation of additional environmental controls, upgrades to the transmission system, and adding or changing fuel sources for certain existing units. The ultimate outcome of these matters cannot be determined at this time. See "PSC Matters – Integrated Resource Plans" herein for additional information on planned unit retirements and fuel conversions.

Southern Electric Generating Company (SEGCO), a subsidiary of the Company, is jointly owned with Alabama Power. As part of its environmental compliance strategy, SEGCO plans to add natural gas as the primary fuel source for its generating units in 2015. The capacity of SEGCO's units is sold equally to the Company and Alabama Power through a PPA. If such compliance costs cannot continue to be recovered through retail rates, they could have a material financial impact on the Company's financial statements. See Note 4 to the Company's financial statements for additional information.

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

Air Quality

Compliance with the Clean Air Act and resulting regulations has been and will continue to be a significant focus for the Company. Since 1990, the Company has spent approximately $3.9 billion in reducing and monitoring emissions pursuant to the Clean Air Act. Additional controls are currently planned or under consideration to further reduce air emissions, maintain compliance with existing regulations, and meet new requirements.

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 more stringent eight-hour ozone NAAQS, which it began to implement in 2011. In May 2012, the EPA published its final determination of nonattainment areas based on the 2008 eight-hour ozone NAAQS. The only area within the Company's service territory designated as a nonattainment area is a 15-county area within metropolitan Atlanta.

The EPA regulates fine particulate matter concentrations on an annual and 24-hour average basis. All areas within the Company's service territory have achieved attainment with the 1997 and 2006 particulate matter NAAQS, and the EPA has officially redesignated some former nonattainment areas within the service territory as attainment for these standards. Redesignation requests for certain areas designated as nonattainment in Georgia are still pending with the EPA. On January 15, 2013, the EPA published a final rule that increases the stringency of the annual fine particulate matter standard. The new standard could result in the designation of new nonattainment areas within the Company's service territory.

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 Company's service territory have been designated as nonattainment under this rule. However, the EPA may designate additional areas as nonattainment in the future, which could include areas within the Company's service territory. Implementation of the revised SO_2 standard could require additional reductions in SO_2 emissions and increased compliance and operational costs.

The Company's service territory is subject to the requirements of the Clean Air Interstate Rule (CAIR), which calls for phased reductions in SO_2 and nitrogen oxide (NO_x) emissions from power plants in 28 eastern states. In 2008, the U.S. Court of Appeals for the District of Columbia Circuit issued decisions invalidating CAIR, but left CAIR compliance requirements in place while the EPA developed a new rule. In 2011, the EPA promulgated the Cross State Air Pollution Rule (CSAPR) to replace CAIR. However, in August 2012, the U.S. Court of Appeals for the District of Columbia Circuit vacated CSAPR in its entirety and directed the EPA to continue to administer CAIR pending the EPA's development of a valid replacement. Review of the U.S. Court of Appeals for the District of Columbia Circuit's decision regarding CSAPR is currently pending before the U.S. Supreme Court.

The EPA finalized the Clean Air Visibility Rule (CAVR) 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 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 February 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. Compliance for existing sources is required by April 16, 2015; however, states may authorize a compliance extension of up to one year to April 16, 2016. Compliance extensions have been granted for some of the Company's affected units.

In August 2012, the EPA published proposed revisions to the New Source Performance Standard (NSPS) for Stationary Combustion Turbines (CTs). 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 February 12, 2013, the EPA proposed a rule that would require certain states to revise the provisions of their State Implementation Plans (SIPs) relating to the regulation of excess emissions at industrial facilities, including fossil fuel-fired generating facilities, during periods of startup, shut-down, or malfunction (SSM). The EPA proposes a determination that the SSM provisions in the SIPs for 36 states, including Georgia, Alabama, and Florida, do not meet the requirements of the Clean Air Act and must be revised within 18 months of the date on which the EPA publishes the final rule. The EPA has entered into a settlement agreement requiring it to finalize the rule by June 12, 2014.

The Company has developed and continually updates a comprehensive environmental compliance strategy to assess compliance obligations associated with the current and proposed environmental requirements discussed above. The impacts of the eight-hour ozone, fine particulate matter and SO_2 NAAQS, CAIR and any future replacement rule, CAVR, the MATS rule, the NSPS for CTs, and the SSM rule on the Company cannot be determined at this time and will depend on the specific provisions of recently finalized and future rules, the resolution of pending and future legal challenges, and the development and implementation of rules at the state level. These regulations could result in significant additional 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. Further, higher costs that are recovered through regulated rates could contribute to reduced demand for electricity, which could negatively impact results of operations, cash flows, and financial condition.

In addition to the federal air quality laws described above, the Company is also subject to the requirements of the 2007 State of Georgia Multi-Pollutant Rule. The Multi-Pollutant Rule, as amended, is designed to reduce emissions of mercury, SO_2, and NOx state-wide by requiring the installation of specified control technologies at certain coal-fired generating units by specific dates between December 31, 2008 and April 16, 2015. A companion rule requires a 95% reduction in SO_2 emissions from the controlled units on the same or similar timetable. Through December 31, 2013, the Company had installed the required controls on 13 of its largest coal-fired generating units with projects on three additional units to be completed before the unit-specific installation deadlines.

Water Quality

In 2011, the EPA published a proposed rule that establishes standards for reducing effects on fish and other aquatic life caused by cooling water intake structures at existing power plants and manufacturing facilities. The rule also addresses cooling water intake structures for new units at existing facilities. Compliance with the proposed rule could require changes to existing cooling water intake structures at certain of the Company's generating facilities, and new generating units constructed at existing plants would be required to install closed cycle cooling towers. The EPA is required to issue a final rule by April 17, 2014.

On June 7, 2013, the EPA published a proposed rule which requested comments on a range of potential regulatory options for addressing certain wastestreams from steam electric power plants. These regulations could result in the installation of additional controls at certain of the facilities of the Company, which could result in significant capital expenditures and compliance costs that could affect future unit retirement and replacement decisions, depending on the specific technology requirements of the final rule.

The impact of these proposed rules cannot be determined at this time and will depend on the specific provisions of the final rules and the outcome of any legal challenges. These 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. Further, higher costs that are recovered through regulated rates could contribute to reduced demand for electricity, which could negatively impact results of operations, cash flows, and financial condition.

MANAGEMENT'S DISCUSSION AND ANALYSIS (continued)
Georgia Power Company 2013 Annual Report

Coal Combustion Residuals
The Company currently operates 11 electric generating plants with on-site coal combustion residuals, including coal ash and gypsum storage facilities. In addition to on-site storage, the Company also sells a portion of its coal combustion residuals to third parties for beneficial reuse. Historically, individual states have regulated coal combustion residuals and the States of Georgia and Alabama have their own separate regulatory requirements. The Company has a routine and robust inspection program in place to ensure the integrity of its coal ash surface impoundments and compliance with applicable regulations.
The EPA continues to evaluate the regulatory program for coal combustion residuals, including coal ash and gypsum, under federal solid and hazardous waste laws. In 2010, the EPA published a proposed rule that requested comments on two potential regulatory options for the management and disposal of coal combustion residuals: regulation as a solid waste or regulation as if the materials technically constituted a hazardous waste. Adoption of either option could require closure of, or significant change to, existing storage facilities and construction of lined landfills, as well as additional waste management and groundwater monitoring requirements. Under both options, the EPA proposes to exempt the beneficial reuse of coal combustion residuals from regulation; however, a hazardous or other designation indicative of heightened risk could limit or eliminate beneficial reuse options. Environmental groups and other parties have filed lawsuits in the U.S. District Court for the District of Columbia seeking to require the EPA to complete its rulemaking process and issue final regulations pertaining to the regulation of coal combustion residuals. On September 30, 2013, the U.S. District Court for the District of Columbia issued an order granting partial summary judgment to the environmental groups and other parties, ruling that the EPA has a statutory obligation to review and revise, as necessary, the federal solid waste regulations applicable to coal combustion residuals. On January 29, 2014, the EPA filed a consent decree requiring the EPA to take final action regarding the proposed regulation of coal combustion residuals as solid waste by December 19, 2014.
While the ultimate outcome of this matter cannot be determined at this time and will depend on the final form of any rules adopted and the outcome of any legal challenges, additional regulation of coal combustion residuals could have a material impact on the generation, management, beneficial use, and disposal of such residuals. Any material changes are likely to result in substantial additional compliance, operational, and capital costs that could affect future unit retirement and replacement decisions. Moreover, the Company could incur additional material asset retirement obligations with respect to closing existing storage facilities. The Company's results of operations, cash flows, and financial condition could be significantly impacted if such costs are not recovered through regulated rates. Further, higher costs that are recovered through regulated rates could contribute to reduced demand for electricity, which could negatively impact results of operations, cash flows, and financial condition.
Environmental Remediation
The Company must comply with other environmental laws and regulations that cover the handling and disposal of waste and releases of hazardous substances. Under these various laws and regulations, the Company may also incur substantial costs to clean up properties. The Company conducts studies to determine the extent of any required cleanup and has recognized in its financial statements the costs to clean up known impacted sites. Amounts for cleanup and ongoing monitoring costs were not material for any year presented. The Company may be liable for some or all required cleanup costs for additional sites that may require environmental remediation. See Notes 1 and 3 to the financial statements under "Environmental Remediation Recovery" and "Environmental Matters – Environmental Remediation," respectively, for additional information.
Global Climate Issues
The EPA currently regulates greenhouse gases under the Prevention of Significant Deterioration and Title V operating permit programs of the Clean Air Act. The legal basis for these regulations is currently being challenged in the U.S. Supreme Court. In addition, over the past several years, the U.S. Congress has considered many proposals to reduce greenhouse gas emissions, mandate renewable or clean energy, and impose energy efficiency standards. Such proposals are expected to continue to be considered by the U.S. Congress. International climate change negotiations

under the United Nations Framework Convention on Climate Change are also continuing.

On January 8, 2014, the EPA published re-proposed regulations to establish standards of performance for greenhouse gas emissions from new fossil fuel steam electric generating units. A Presidential memorandum issued on June 25, 2013 also directs the EPA to propose standards, regulations, or guidelines for addressing modified, reconstructed, and existing steam electric generating units by June 1, 2014.

Although the outcome of any federal, state, and international initiatives, including the EPA's proposed regulations and guidelines discussed above, will depend on the scope and specific requirements of the proposed and final rules and the outcome of any legal challenges and, therefore, cannot be determined at this time, additional restrictions on the Company's greenhouse gas emissions or requirements relating to renewable energy or energy efficiency at the federal or state level could result in significant additional

MANAGEMENT'S DISCUSSION AND ANALYSIS (continued)
Georgia Power Company 2013 Annual Report

compliance costs, including capital expenditures. These costs could affect future unit retirement and replacement decisions and could result in the retirement of additional coal-fired generating units. Also, additional compliance costs and costs related to unit retirements could affect results of operations, cash flows, and financial condition if such costs are not recovered through regulated rates. Further, higher costs that are recovered through regulated rates could contribute to reduced demand for electricity, which could negatively impact results of operations, cash flows, and financial condition.

The EPA's greenhouse gas reporting rule requires annual reporting of carbon dioxide equivalent emissions in metric tons for a company's operational control of facilities. Based on ownership or financial control of facilities, the Company's 2012 greenhouse gas emissions were approximately 32 million metric tons of carbon dioxide equivalent. The preliminary estimate of the Company's 2013 greenhouse gas emissions on the same basis is approximately 33 million metric tons of carbon dioxide equivalent. The level of greenhouse gas emissions from year to year will depend on the level of generation and mix of fuel sources and other factors.

PSC Matters

Rate Plans

In 2010, the Georgia PSC approved the 2010 ARP, which resulted in base rate increases of approximately $562 million, $17 million, $125 million, and $74 million effective January 1, 2011, January 1, 2012, April 1, 2012, and January 1, 2013, respectively.

On December 17, 2013, the Georgia PSC voted to approve the 2013 ARP. The 2013 ARP reflects the settlement agreement among the Company, the Georgia PSC’s Public Interest Advocacy Staff, and 11 of the 13 intervenors, which was filed with the Georgia PSC on November 18, 2013.

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

Under the 2013 ARP, the following additional rate adjustments will be made to the Company’s tariffs in 2015 and 2016 based on annual compliance filings to be made at least 90 days prior to the effective date of the tariffs:

- Effective January 1, 2015 and 2016, the traditional base tariff rates will increase by an estimated $101 million and $36 million, respectively, to recover additional generation capacity-related costs;
- Effective January 1, 2015 and 2016, the ECCR tariff will increase by an estimated $76 million and $131 million, respectively, to recover additional environmental compliance costs;
- Effective January 1, 2015, the DSM tariffs will increase by an estimated $6 million and decrease by an estimated $1 million effective January 1, 2016; and
- The MFF tariff will increase consistent with these adjustments.

The Company currently estimates these adjustments will result in base revenue increases of approximately $187 million in 2015 and $170 million in 2016. The estimated traditional base tariff rate increases for 2015 and 2016 do not include additional Qualifying Facility (QF) PPA expenses; however, compliance filings will include QF PPA expenses for those facilities that are projected to provide capacity to the Company during the following year.

Under the 2013 ARP, the Company’s retail return on common equity (ROE) is set at 10.95%, and earnings are evaluated against a retail ROE range of 10.00% to 12.00%. Two-thirds of any earnings above 12.00% will be directly refunded to customers, with the remaining one-third retained by the Company. There will be no recovery of any earnings shortfall below 10.00% on an actual basis. However, if at any time during the term of the 2013 ARP, the Company projects that its retail earnings will be below 10.00% for any calendar year, it may petition the Georgia PSC for implementation of the Interim Cost Recovery (ICR) tariff that would be used to adjust the Company’s earnings back to a 10.00% retail ROE. The Georgia PSC would have 90 days to rule on the Company’s request. The ICR tariff will expire at the earlier of January 1, 2017 or the end of the calendar year in which the ICR tariff becomes effective. In lieu of requesting implementation of an ICR tariff, or if the Georgia PSC chooses not to implement the ICR tariff, the Company may file a full rate case.

Except as provided above, the Company will not file for a general base rate increase while the 2013 ARP is in effect. The Company is required to file a general 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.

MANAGEMENT'S DISCUSSION AND ANALYSIS (continued)
Georgia Power Company 2013 Annual Report

Integrated Resource Plans
See "Environmental Matters – Environmental Statutes and Regulations – Air Quality," "– Water Quality," and "– Coal Combustion Residuals" 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 regulation of coal combustion residuals; the State of Georgia's Multi-Pollutant Rule; the Company's analysis of the potential costs and benefits of installing the required controls on its fossil generating units in light of these regulations; and the Company's latest triennial IRP as approved by the Georgia PSC (2013 IRP).
On January 31, 2013, the Company filed its 2013 IRP. The filing included the Company's request to decertify 16 coal- and oil-fired units totaling 2,093 MWs. Several factors, including the cost to comply with existing and future environmental regulations, recent and forecasted economic conditions, and lower natural gas prices, contributed to the decision to close these units.
On April 17, 2013, the Georgia PSC approved the decertification of Plant Bowen Unit 6 (32 MWs), which was retired on April 25, 2013. On September 30, 2013, Plant Branch Unit 2 (319 MWs) was retired as approved by the Georgia PSC in the 2011 IRP Update (2011 IRP Update) in order to comply with the State of Georgia's Multi-Pollutant Rule.
On July 11, 2013, the Georgia PSC approved the Company's request to decertify and retire Plant Boulevard Units 2 and 3 (28 MWs) effective July 17, 2013. Plant Branch Units 3 and 4 (1,016 MWs), Plant Yates Units 1 through 5 (579 MWs), and Plant McManus Units 1 and 2 (122 MWs) will be decertified and retired by April 16, 2015, the compliance date of the MATS rule. The decertification date of Plant Branch Unit 1 was extended from December 31, 2013 as specified in the final order in the 2011 IRP Update to coincide with the decertification date of Plant Branch Units 3 and 4. The decertification and retirement of Plant Kraft Units 1 through 4 (316 MWs) was also approved and will be effective by April 16, 2016, based on a one-year extension of the MATS rule compliance date that was approved by the State of Georgia Environmental Protection Division on September 10, 2013 to allow for necessary transmission system reliability improvements.
Additionally, the Georgia PSC approved the Company's proposed MATS rule compliance plan for emissions controls necessary for the continued operation of Plants Bowen Units 1 through 4, Wansley Units 1 and 2, Scherer Units 1 through 3, and Hammond Units 1 through 4, the switch to natural gas as the primary fuel at Plant Yates Units 6 and 7 and SEGCO's Plant Gaston Units 1 through 4, as well as the fuel switch at Plant McIntosh Unit 1 to operate on Powder River Basin coal. See Note 1 to the financial statements under "Affiliate Transactions" for additional information regarding the fuel switch at SEGCO's generating units.
In the 2013 ARP, the Georgia PSC approved the amortization of the construction work in progress (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 beginning in January 2014 and the amortization of any 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. The Georgia PSC deferred a decision regarding the appropriate recovery period for the costs associated with unusable materials and supplies remaining at the retiring plants to the Company's next base rate case, which the Company expects to file in 2016 (2016 Rate Case). In the 2013 IRP, the Georgia PSC also deferred decisions regarding the recovery of any fuel related costs that could be incurred in connection with the retirement units to be addressed in future fuel cases.
A request was filed with the Georgia PSC on January 10, 2014 to cancel the proposed biomass fuel conversion of Plant Mitchell Unit 3 (155 MWs) because it would not be cost effective for customers. The filing also notified the Georgia PSC of the Company’s plans to seek decertification later this year. Plant Mitchell Unit 3 will continue to operate as a coal unit until April 2015 when it will be required to cease operation or install additional environmental controls to comply with the MATS rule. In connection with the retirement decision, the Company reclassified the retail portion of the net carrying value of Plant Mitchell Unit 3 from plant in service, net of depreciation, to other

utility plant, net.

The decertification of these units and fuel conversions are not expected to have a material impact on the Company's financial statements; however, the ultimate outcome depends on the Georgia PSC's order in the 2016 Rate Case and future fuel cases and cannot be determined at this time.

Renewables Development

On December 17, 2013, four PPAs totaling 50 MWs of utility scale solar generation under the Georgia Power Advanced Solar Initiative (GPASI) were approved by the Georgia PSC, with the Company as the purchaser. These contracts will begin in 2015 and end in 2034. The resulting purchases will be for energy only and recovered through the Company’s fuel cost recovery mechanism. Under the 2013 IRP, the Georgia PSC approved an additional 525 MWs of solar generation to be purchased by the Company. The 525 MWs will be divided into 425 MWs of utility scale projects and 100 MWs of distributed generation.

MANAGEMENT'S DISCUSSION AND ANALYSIS (continued)
Georgia Power Company 2013 Annual Report

On November 4, 2013, the Company filed an application for the certification of two PPAs which were executed on April 22, 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.

During 2013, the Company executed four PPAs to purchase a total of 169 MWs of biomass capacity and energy from four facilities in Georgia that will begin in 2015 and end in 2035. On May 21, 2013, the Georgia PSC approved two of the biomass PPAs and the remaining two were approved on December 17, 2013. The four biomass PPAs are contingent upon the counterparty meeting specified contract dates for posting collateral and commercial operation. The ultimate outcome of this matter cannot be determined at this time.

Fuel Cost Recovery

The Company has established fuel cost recovery rates approved by the Georgia PSC. The Georgia PSC approved reductions in the Company's total annual billings of approximately $43 million effective June 1, 2011, $567 million effective June 1, 2012, and $122 million effective January 1, 2013. The 2013 reduction was due to the Georgia PSC authorizing an Interim Fuel Rider, which is set to expire June 1, 2014. The Company 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. The Company's fuel cost recovery includes costs associated with a natural gas hedging program as revised and approved by the Georgia PSC on February 7, 2013. See FINANCIAL CONDITION AND LIQUIDITY – "Market Price Risk" herein and Note 11 to the financial statements under "Energy-Related Derivatives" for additional information. On February 18, 2014, the Georgia PSC approved the deferral of the Company's next fuel case, which is now expected to be filed by March 1, 2015.

The Company's over recovered fuel balance totaled approximately $58 million and $230 million at December 31, 2013 and December 31, 2012, respectively, and is included in current liabilities and other deferred credits and liabilities.

Fuel cost recovery revenues as recorded on the financial statements are adjusted for differences in actual recoverable fuel costs and amounts billed in current regulated rates. Accordingly, changes in the billing factor will not have a significant effect on the Company's revenues or net income, but will affect cash flow. See Note 3 to the financial statements under "Retail Regulatory Matters – Fuel Cost Recovery" for additional information.

Storm Damage Recovery

The Company defers and recovers certain costs related to damages from major storms as mandated by the Georgia PSC. As of December 31, 2013, the balance in the regulatory asset related to storm damage was $37 million. As a result of this regulatory treatment, the costs related to storms are generally not expected to have a material impact on the Company's financial statements. See Note 1 to the financial statements under "Storm Damage Recovery" for additional information.

Nuclear Construction

In 2008, the Company, acting for itself and as agent for Oglethorpe Power Corporation (OPC), the Municipal Electric Authority of Georgia (MEAG Power), and the City of Dalton, Georgia (Dalton), acting by and through its Board of Water, Light, and Sinking Fund Commissioners (collectively, Owners), entered into an agreement with a consortium consisting of Westinghouse Electric Company LLC (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 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. Each Owner is severally (and not jointly) liable for its proportionate share, based on its ownership interest, of all amounts owed to the Contractor under the Vogtle 3 and 4 Agreement. The Company's proportionate share is 45.7%. The Vogtle 3 and 4 Agreement provides for liquidated damages upon the Contractor's failure to fulfill the schedule and performance guarantees. The Contractor's liability to the Owners for schedule and performance liquidated damages and warranty claims is subject to a cap.

Certain payment obligations of Westinghouse and Stone & Webster, Inc. under the Vogtle 3 and 4 Agreement are guaranteed by Toshiba Corporation and The Shaw Group, Inc., respectively. In the event of certain credit rating downgrades of any Owner, such Owner will be required to provide a letter of credit or other credit enhancement. The Owners may terminate the Vogtle 3 and 4 Agreement at any time for their convenience, provided that the Owners will be required to pay certain termination costs. The Contractor may terminate the Vogtle 3 and 4 Agreement under certain circumstances, including certain 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 Owners, Owner insolvency, and certain other events.

In 2009, the U.S. Nuclear Regulatory Commission (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, effective December 30, 2011, and issued combined construction and operating licenses (COLs) in February 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 are expected as construction proceeds.

In 2009, the Georgia PSC approved inclusion of the Plant Vogtle Units 3 and 4 related CWIP accounts in rate base, and the State of Georgia enacted the Georgia Nuclear Energy Financing Act, which allows the Company to recover financing costs for nuclear construction projects certified by the Georgia PSC. Financing costs are recovered on all applicable certified costs through annual adjustments to the NCCR tariff by including the related CWIP accounts in rate base during the construction period. The Georgia PSC approved increases to the NCCR tariff of approximately $223 million, $35 million, $50 million, and $60 million, effective January 1, 2011, 2012, 2013, and 2014, respectively. Through the NCCR tariff, the Company is collecting and amortizing to earnings approximately $91 million of financing costs, capitalized in 2009 and 2010, over the five-year period ending December 31, 2015, in addition to the ongoing financing costs. At December 31, 2013, approximately $37 million of these 2009 and 2010 costs remained unamortized in CWIP.

The Company is required to file semi-annual Vogtle Construction Monitoring (VCM) reports with the Georgia PSC by February 28 and August 31 each year. If the projected certified construction capital costs to be borne by the Company increase by 5% or the projected in-service dates are significantly extended, the Company is required to seek an amendment to the Plant Vogtle Units 3 and 4 certificate from the Georgia PSC. Accordingly, the Company's eighth VCM report 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 and the fourth quarter 2018 for Plant Vogtle Units 3 and 4, respectively.

On September 3, 2013, the Georgia PSC approved a stipulation entered into by the Company and the Georgia PSC staff to waive the requirement to amend the Plant Vogtle Units 3 and 4 certificate, until the commercial operation date of Plant Vogtle Unit 3, or earlier if deemed appropriate by the Georgia PSC and the Company. In accordance with the Georgia Integrated Resource Planning Act, any costs incurred by the Company in excess of the certified amount will not be included in rate base, unless shown to be reasonable and prudent. In addition, financing costs on any excess construction-related costs potentially would be subject to recovery through AFUDC instead of the NCCR tariff. As required by the stipulation, the Company filed an abbreviated status update with the Georgia PSC on September 3, 2013, which reflected approximately $2.4 billion of total construction capital costs incurred through June 30, 2013.

On October 15, 2013, the Georgia PSC voted to approve the Company's eighth VCM report, reflecting construction capital costs incurred, which through December 31, 2012 totaled approximately $2.2 billion. Also in accordance with the stipulation, the Company will file with the Georgia PSC on February 28, 2014 a combined ninth and tenth VCM report covering the period from January 1 through December 31, 2013 (Ninth/Tenth VCM report), which will request approval for an additional $0.4 billion of construction capital costs. The Ninth/Tenth VCM report will reflect estimated in-service construction capital costs of $4.8 billion and associated financing costs during the construction period, which are estimated to total approximately $2.0 billion. The Company expects to resume filing semi-annual VCM reports in August 2014.

In July 2012, the Owners and the Contractor began negotiations 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 Owners are responsible for these costs under the terms of the Vogtle 3 and 4 Agreement. The portion of the additional costs claimed by the Contractor that would be attributable to the Company (based on the Company's ownership interest) with respect to these issues is approximately $425 million (in 2008 dollars). The Contractor also has asserted it is entitled to further schedule extensions. The Company has not agreed with either the proposed cost or schedule adjustments or that the Owners have any responsibility for costs related to these issues. In November 2012, the Company and the other Owners filed suit against the Contractor in the U.S. District Court for the Southern District of Georgia seeking a declaratory judgment that the Owners are not responsible for these costs. Also in November 2012, the Contractor filed suit against the Company and the other Owners in the U.S. District Court for the District of Columbia alleging the Owners are responsible for these costs. On August 30, 2013, the U.S. District Court for the District of Columbia dismissed the Contractor's suit, ruling that the proper venue is the U.S. District Court for the Southern District of Georgia. The Contractor appealed the decision to the U.S. Court of Appeals for the District of Columbia Circuit on September 27, 2013. While litigation has commenced and the Company intends to vigorously defend its positions, the Company also expects negotiations with the Contractor to continue with respect to cost and schedule during which negotiations the parties may reach a mutually acceptable compromise of their positions.

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

MANAGEMENT'S DISCUSSION AND ANALYSIS (continued)
Georgia Power Company 2013 Annual Report

licensing-based compliance issues are expected to 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 Owners, the Contractor, or both.

As construction continues, the risk remains that additional challenges in the fabrication, assembly, delivery, and installation of 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. Additional claims by the Contractor or the Company (on behalf of the Owners) are also likely to arise throughout construction. These claims may be resolved through formal and informal dispute resolution procedures under the Vogtle 3 and 4 Agreement, but also may be resolved through litigation.

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

Income Tax Matters

Bonus Depreciation

On January 2, 2013, the American Taxpayer Relief Act of 2012 (ATRA) was signed into law. The ATRA retroactively extended several tax credits through 2013 and extended 50% bonus depreciation for property placed in service in 2013 (and for certain long-term production-period projects to be placed in service in 2014). The extension of 50% bonus depreciation had a positive impact on the Company's cash flows of approximately $150 million in 2013 and is expected to have a positive impact between $40 million and $50 million on the cash flows of the Company in 2014.

Other Matters

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

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

In 2011, a major earthquake and tsunami struck Japan and caused substantial damage to the nuclear generating units at the Fukushima Daiichi generating plant. The events in Japan have created uncertainties that may affect future costs for operating nuclear plants. Specifically, the NRC is performing additional operational and safety reviews of nuclear facilities in the U.S., which could potentially impact future operations and capital requirements. In addition, the NRC has issued a series of orders requiring safety-related changes to U.S. nuclear facilities and expects to issue orders in the future requiring additional upgrades. The final form and the resulting impact of any changes to safety requirements for nuclear reactors will be dependent on further review and action by the NRC and cannot be determined at this time; however, management does not currently anticipate that the compliance costs associated with these orders would have a material impact on the Company's financial statements.

Additionally, there are certain risks associated with the operation of nuclear generating units, including potential impacts that could result from a major incident at a nuclear facility anywhere in the world. The ultimate outcome of these events cannot be determined at this time.

On April 4, 2013, an explosion occurred at Plant Bowen Unit 2 that resulted in substantial damage to the Plant Bowen Unit 2 generator, the Plant Bowen Units 1 and 2 control room and surrounding areas, and Plant Bowen's switchyard. Plant Bowen Unit 1 (approximately 700 MWs) was returned to service on August 4, 2013 and Plant Bowen Unit 2 (approximately 700 MWs) was returned to service on December 20, 2013. The Company expects that any material repair costs related to the damage will be covered by property insurance.

On November 19, 2013, the U.S. District Court for the District of Columbia ordered the U.S. Department of Energy (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. In accordance with the court's order, the DOE has submitted a proposal to the U.S. Congress to change the fee to zero. That proposal is pending before the U.S. Congress and will become effective after 90 days of legislative session from the time of submittal unless the U.S. Congress enacts legislation that impacts the proposed fee change. The DOE's petition for rehearing of the November 2013 decision is currently pending and the Company is continuing to pay the fee of approximately $15 million annually based on its ownership interest. The ultimate outcome of this matter cannot be determined at this time.

ACCOUNTING POLICIES

Application of Critical Accounting Policies and Estimates

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

Electric Utility Regulation

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

Contingent Obligations

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

Pension and Other Postretirement Benefits

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

Key elements in determining the Company's pension and other postretirement benefit expense in accordance with GAAP 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 postretirement benefit plan assets is based on the

Company's investment strategy, historical experience, and expectations for long-term rates of return that consider external actuarial advice. The Company determines the long-term return on plan assets by applying the long-term rate of expected returns on various asset classes to the Company's target asset allocation. The Company discounts the future cash flows related to its postretirement benefit plans using a single-point discount rate developed from the weighted average of market-observed yields for high quality fixed income securities with maturities that correspond to expected benefit payments.

A 25 basis point change in any significant assumption (discount rate, salaries, or long-term return on plan assets) would result in an $8 million or less change in total annual benefit expense and a $121 million or less change in projected obligations.

FINANCIAL CONDITION AND LIQUIDITY

Overview

The Company's financial condition remained stable at December 31, 2013. The Company's cash requirements primarily consist of funding ongoing operations, common stock dividends, capital expenditures, and debt maturities. Capital expenditures and other investing activities include investments to meet projected long-term demand requirements, to comply with environmental regulations, and for restoration following major storms. Operating cash flows provide a substantial portion of the Company's cash needs. For the three-year period from 2014 through 2016, the Company's projected common stock dividends, capital expenditures, and debt maturities are expected to exceed operating cash flows. Projected capital expenditures in that period include investments to build new generation facilities, including Plant Vogtle Units 3 and 4, to maintain existing generation facilities, to add environmental equipment for existing generating units, and to expand and improve transmission and distribution facilities. The Company plans to finance future cash needs in excess of its operating cash flows primarily through debt issuances and capital contributions from Southern Company. The Company intends to continue to monitor its access to short-term and long-term capital markets as well as its bank credit arrangements to meet future capital and liquidity needs. See "Sources of Capital," "Financing Activities," and "Capital Requirements and Contractual Obligations" herein for additional information.

The Company's investments in the qualified pension plan and the nuclear decommissioning trust funds increased in value as of December 31, 2013 as compared to December 31, 2012. No contributions to the qualified pension plan were made in 2013. The Company funded approximately $2 million to its nuclear decommissioning trust funds in 2013. See "Contractual Obligations" herein for additional information.

Net cash provided from operating activities totaled $2.8 billion in 2013, an increase of $471 million from 2012, primarily due to higher retail operating revenues, lower fuel inventory additions, and settlement of affiliated payables related to pension funding in 2012, partially offset by fuel cost recovery. Net cash provided from operating activities totaled $2.3 billion in 2012, a decrease of $337 million from 2011, primarily due to higher fuel inventory additions in 2012 and lower deferred taxes due to the effect of bonus depreciation in 2011, partially offset by higher recovery of retail fuel costs.

Net cash used for investing activities totaled $1.9 billion, $2.0 billion, and $1.8 billion in 2013, 2012, and 2011, respectively, due to gross property additions primarily related to installation of equipment to comply with environmental standards; construction of generation, transmission, and distribution facilities; and purchase of nuclear fuel. The majority of funds needed for gross property additions for the last several years has been provided from operating activities, capital contributions from Southern Company, and the issuance of debt.

Net cash used for financing activities totaled $891 million, $290 million, and $836 million for 2013, 2012, and 2011, respectively. The increase in cash used in 2013 compared to 2012 was primarily due to lower net issuances of long-term debt in 2013, partially offset by an increase in net short-term borrowings. The decrease in cash used in 2012 compared to 2011 was primarily due to additional debt issuances in 2012 to support the ongoing construction program. See "Financing Activities" herein for additional information. 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 2013 include an increase of $959 million in total property, plant, and equipment, a decrease of $250 million in fossil fuel stock, and a decrease in other regulatory assets, deferred of $646 million related to pension and other postretirement benefits.

The Company's ratio of common equity to total capitalization, including short-term debt, was 49.1% in 2013 and 48.3% in 2012. See Note 6 to the financial statements for additional information.

Sources of Capital

Except as described below with respect to the DOE loan guarantees, the Company plans to obtain the funds required for construction and other purposes from sources similar to those used in the past, which were primarily from operating cash flows,

MANAGEMENT'S DISCUSSION AND ANALYSIS (continued)
Georgia Power Company 2013 Annual Report

short-term debt, security issuances, term loans, and equity contributions from Southern Company. However, the amount, type, and timing of any future financings, if needed, will depend upon regulatory approvals, prevailing market conditions, and other factors.

On February 20, 2014, the Company and the DOE entered into a loan guarantee agreement (Loan Guarantee Agreement), pursuant to which the DOE agreed to guarantee borrowings to be made by the Company under a multi-advance credit facility (FFB Credit Facility) among the Company, the DOE, and the Federal Financing Bank (FFB). The Company's reimbursement obligations to the DOE are secured by a first priority lien on (i) the Company's 45.7% undivided ownership interest in Plant Vogtle Units 3 and 4 and (ii) the Company's rights and obligations under the principal contracts relating to Plant Vogtle Units 3 and 4. Under the FFB Credit Facility, the Company may make term loan borrowings through the FFB. Proceeds of borrowings made under the FFB Credit Facility will be used to reimburse the Company for a portion of certain costs of construction relating to Plant Vogtle Units 3 and 4 that are eligible for financing under the Loan Guarantee Agreement (Eligible Project Costs). 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. See Note 6 to the financial statements for additional information.

The issuance of long-term securities by the Company is subject to the approval of the Georgia PSC. In addition, the issuance of short-term debt securities by the Company is subject to regulatory approval by the FERC. Additionally, with respect to the public offering of securities, the Company files registration statements with the U.S. Securities and Exchange Commission (SEC) under the Securities Act of 1933, as amended. The amounts of securities authorized by the Georgia PSC and the FERC are continuously monitored and appropriate filings are made to ensure flexibility in the capital markets.

The Company obtains financing separately without credit support from any affiliate. See Note 6 to the financial statements under "Bank Credit Arrangements" for additional information. The Southern Company system does not maintain a centralized cash or money pool. Therefore, funds of the Company are not commingled with funds of any other company in the Southern Company system.

The Company's current liabilities frequently exceed current assets because of the continued use of short-term debt as a funding source to meet scheduled maturities of long-term debt, as well as cash needs, which can fluctuate significantly due to the seasonality of the Company's business. The Company has substantial cash flow from operating activities and access to the capital markets to meet liquidity needs. At December 31, 2013, the Company had approximately $30 million of cash and cash equivalents. Committed credit arrangements with banks at December 31, 2013 were as follows:

Expires[(a)]			
2016	2018	Total	Unused
	(in millions)		
$150	$1,600	$1,750	$1,736

(a) No credit arrangements expire in 2014, 2015, or 2017.

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

A portion of the unused credit with banks is allocated to provide liquidity support to the Company's variable rate pollution control revenue bonds and commercial paper borrowings. The amount of variable rate pollution control revenue bonds outstanding requiring liquidity support as of December 31, 2013 was approximately $862 million. In addition, at December 31, 2013, the Company had $242 million of fixed rate pollution control revenue bonds that will be required to be remarketed within the next 12 months.

These arrangements contain covenants that limit debt levels and contain cross default provisions to other indebtedness (including guarantee obligations) of the Company. Such cross default provisions to other indebtedness would trigger an event of default if the Company defaulted on indebtedness or guarantee obligations over a specified threshold. The Company is currently in compliance with all such covenants. None of the arrangements contain material adverse change clauses at the time of borrowings. The Company expects to renew its credit arrangements, as needed, prior to

expiration.
The Company may also meet short-term cash needs through a Southern Company subsidiary organized to issue and sell commercial paper at the request and for the benefit of the Company and the other traditional operating companies. Proceeds from such issuances for the benefit of the Company are loaned directly to the Company. The obligations of each company under these arrangements are several and there is no cross affiliate credit support.

MANAGEMENT'S DISCUSSION AND ANALYSIS (continued)
Georgia Power Company 2013 Annual Report

Details of short-term borrowings were as follows:

	Short-term Debt at the End of the Period(a)		Short-term Debt During the Period (b)		
	Amount Outstanding (in millions)	Weighted Average Interest Rate	Average Outstanding (in millions)	Weighted Average Interest Rate	Maximum Amount Outstanding (in millions)
December 31, 2013:					
Commercial paper	$647	0.2 %	$166	0.2 %	$702
Short-term bank debt	400	0.9 %	96	0.9 %	400
Total	$1,047	0.5 %	$262	0.5 %	
December 31, 2012:					
Commercial paper	$—	— %	$78	0.2 %	$517
Short-term bank debt	—	— %	116	1.2 %	300
Total	$—	— %	$194	0.8 %	
December 31, 2011:					
Commercial paper	$313	0.2 %	$208	0.3 %	$681
Short-term bank debt	200	1.2 %	9	1.2 %	200
Total	$513	0.5 %	$217	0.3 %	

(a) Excludes notes payable related to other energy service contracts of $2 million in 2012 and 2011.
(b) Average and maximum amounts are based upon daily balances during the twelve-month periods ended December 31, 2013, 2012, and 2011.

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

Financing Activities

In addition to any financings that may be necessary to meet capital requirements and contractual obligations, the Company plans to continue, when economically feasible, a program to retire higher-cost securities and replace these obligations with lower-cost capital if market conditions permit.

Pollution Control Revenue Bonds

In March 2013, the Development Authority of Monroe County issued $17.5 million aggregate principal amount of Pollution Control Revenue Bonds (Georgia Power Company Plant Scherer Project), First Series 2013 due April 1, 2043 for the benefit of the Company. The proceeds were used to redeem, in April 2013, $17.5 million aggregate principal amount of Development Authority of Monroe County (Georgia) Pollution Control Revenue Bonds (Georgia Power Company Plant Scherer Project), Second Series 1997.

In August 2013, the Development Authority of Bartow County issued $71.7 million aggregate principal amount of Pollution Control Revenue Bonds (Georgia Power Company Plant Bowen Project), First Series 2013 due August 1, 2043 for the benefit of the Company. The proceeds were used to redeem, in September 2013, $24.9 million and $46.8 million aggregate principal amount of Development Authority of Bartow County (Georgia) Pollution Control Revenue Bonds (Georgia Power Company Plant Bowen Project), First Series 1996 and 1998, respectively.

In November 2013, the Development Authority of Burke County issued $104.6 million aggregate principal amount of Development Authority of Burke County (Georgia) Pollution Control Revenue Bonds (Georgia Power Company Plant Vogtle Project), First Series 2013 due November 1, 2053 for the benefit of the Company. The proceeds were used to redeem, in November 2013, $55 million and $49.6 million aggregate principal amount of Development Authority of Burke County (Georgia) Pollution Control Revenue Bonds (Georgia Power Company Plant Vogtle Project), Third Series 1994 and First Series 1997, respectively. Also in November 2013, the Company purchased and now holds $104.6 million aggregate principal amount of pollution control revenue bonds issued for its benefit in 2013. The

Company may reoffer these bonds to the public at a later date.

MANAGEMENT'S DISCUSSION AND ANALYSIS (continued)
Georgia Power Company 2013 Annual Report

Senior Notes
In January 2013, the Company's $300 million aggregate principal amount of Series 2011A Floating Rate Senior Notes was paid at maturity.
In March 2013, the Company issued $400 million aggregate principal amount of Series 2013A 4.30% Senior Notes due March 15, 2043. Also in March 2013, the Company issued $250 million aggregate principal amount of Series 2013B Floating Rate Senior Notes due March 15, 2016. The proceeds from these sales were used to repay at maturity $350 million aggregate principal amount of the Company's Series 2010A Floating Rate Senior Notes due March 15, 2013, to repay a portion of its outstanding short-term indebtedness, and for general corporate purposes, including the Company's continuous construction program.
In August 2013, the Company issued $200 million aggregate principal amount of Series 2013C Floating Rate Senior Notes due August 15, 2016. The proceeds were used to repay at maturity a portion of $100 million aggregate principal amount outstanding of the Company's Series Q 4.90% Senior Notes and a portion of $500 million aggregate principal amount outstanding of the Company's Series 2010D 1.30% Senior Notes, both due September 15, 2013.
In November 2013, the Company redeemed $100 million aggregate principal amount of its Series 2008C 8.20% Senior Notes due November 1, 2048. In November and December 2013, the Company’s $400 million aggregate principal amount of 2008D 6.00% Senior Notes and $25 million aggregate principal amount of Series E 4.90% Senior Notes, respectively, were paid at maturity.
Other
In March 2013, the Company entered into three 60-day floating rate bank loans bearing interest based on one-month London Interbank Offered Rate (LIBOR). Each of these short-term loans was for $100 million aggregate principal amount, and the proceeds were used for working capital and other general corporate purposes, including the Company's continuous construction program. These bank loans were repaid at maturity.
In November 2013, the Company entered into three four-month floating rate bank loans for an aggregate principal amount of $400 million, bearing interest based on one-month LIBOR. The proceeds of these short-term loans were used for working capital and other general corporate purposes, including the Company's continuous construction program. Subsequent to December 31, 2013, the Company repaid these bank term loans.
These bank loans have 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 other hybrid securities. At December 31, 2013, the Company was in compliance with its debt limits.
In addition, these bank loans contain cross default provisions to other indebtedness (including guarantee obligations) that would be triggered if the Company defaulted on indebtedness above a specified threshold. The Company is currently in compliance with all such covenants.
DOE Loan Guarantee Borrowings
Subsequent to December 31, 2013, the Company 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 February 20, 2044 (the final maturity date) and the interest rate applicable to the remaining $500 million is 3.488% for an interest period that extends to February 20, 2029 and will be reset from time to time thereafter through the final maturity date. The final maturity date for all advances under the FFB Credit Facility is February 20, 2044. The proceeds of the initial borrowings under the FFB Credit Facility were used to reimburse the Company for Eligible Project Costs relating to the construction of Plant Vogtle Units 3 and 4. The Company's reimbursement obligations to the DOE are secured by a first priority lien on (i) the Company's 45.7% undivided ownership interest in Plant Vogtle Units 3 and 4 and (ii) the Company's rights and obligations under the principal contracts relating to Plant Vogtle Units 3 and 4. Under the Loan Guarantee Agreement, Georgia Power is subject to customary events of default, as well as cross-defaults to other indebtedness and events of default relating to any failure to make payments under the Vogtle 3 and 4 Agreement or certain other agreements providing intellectual property rights for Plant Vogtle Units 3 and 4. The Loan Guarantee Agreement also includes

events of default specific to the DOE loan guarantee program, including the failure of Georgia Power or Southern Nuclear to comply with requirements of law or DOE loan guarantee program requirements. See Note 6 to the financial statements for additional information.

Credit Rating Risk

The Company does not have any credit arrangements that would require material changes in payment schedules or terminations as a result of a credit rating downgrade. There are certain contracts that could require collateral, but not accelerated payment, in the event of a credit rating change to BBB- and/or Baa3 or below. These contracts are for physical electricity purchases and sales, fuel purchases, fuel transportation and storage, energy price risk management, and construction of new generation. The maximum potential collateral requirements under these contracts at December 31, 2013 were as follows:

Credit Ratings	Maximum Potential Collateral Requirements
	(in millions)
At BBB- and/or Baa3	$88
Below BBB- and/or Baa3	1,318

Included in these amounts are 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. Additionally, any credit rating downgrade could impact the Company's ability to access capital markets, particularly the short-term debt market and the variable rate pollution control revenue bond market.

On May 24, 2013, Standard and Poor's Ratings Services, a division of the McGraw Hill Companies, Inc. revised the ratings outlook for Southern Company and the traditional operating companies, including the Company, from stable to negative.

Market Price Risk

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

To mitigate future exposure to changes in interest rates, the Company may enter into derivatives designated as hedges. The weighted average interest rate on $1.3 billion of outstanding variable rate long-term debt at January 1, 2014 was 0.25%. If the Company sustained a 100 basis point change in interest rates for all unhedged variable rate long-term debt, the change would affect annualized interest expense by approximately $13 million at January 1, 2014. See Note 1 to the financial statements under "Financial Instruments" and Note 11 to the financial statements for additional information.

To mitigate residual risks relative to movements in electricity prices, the Company enters into physical fixed-price contracts for the purchase and sale of electricity through the wholesale electricity market and, to a lesser extent, financial hedge contracts for natural gas purchases. The Company continues to manage a fuel-hedging program implemented per the guidelines of the Georgia PSC. The Company had no material change in market risk exposure for the year ended December 31, 2013 when compared to the December 31, 2012 reporting period.

MANAGEMENT'S DISCUSSION AND ANALYSIS (continued)
Georgia Power Company 2013 Annual Report

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:

	2013 Changes	2012 Changes
	Fair Value	
	(in millions)	
Contracts outstanding at the beginning of the period, assets (liabilities), net	$(34)	$(82)
Contracts realized or settled:		
Swaps realized or settled	9	53
Options realized or settled	20	18
Current period changes[(a)]:		
Swaps	1	(9)
Options	(12)	(14)
Contracts outstanding at the end of the period, assets (liabilities), net	$(16)	$(34)

(a) 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:

	2013	2012
	mmBtu* Volume	
	(in millions)	
Commodity – Natural gas swaps	7	12
Commodity – Natural gas options	52	93
Total hedge volume	59	105

*million British thermal units (mmBtu)

The weighted average swap contract cost above market prices was approximately $0.50 per mmBtu as of December 31, 2013 and $1.09 per mmBtu as of December 31, 2012. The change in option fair value is primarily attributable to the volatility of the market and the underlying change in the natural gas price. All natural gas hedge gains and losses are recovered through the Company's fuel cost recovery mechanism.

At December 31, 2013 and 2012, substantially all of the Company's energy-related derivative contracts were designated as regulatory hedges and are related to the Company's fuel-hedging program, which previously had a 48-month time horizon. In February 2013, the Georgia PSC approved changes to the Company's hedging program requiring it to use options and hedges within a 24-month time horizon. Hedging gains and losses are initially recorded as regulatory liabilities and assets, respectively, and then are included in fuel expense as they are recovered through the fuel cost recovery mechanism. Gains and losses on energy-related derivative contracts that are not designated or fail to qualify as hedges are recognized in the statements of income as incurred and were not material for any year presented.

MANAGEMENT'S DISCUSSION AND ANALYSIS (continued)
Georgia Power Company 2013 Annual Report

The Company uses over-the-counter contracts that are not exchange traded but are fair valued using prices which are market observable, and thus fall into Level 2. 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, 2013 were as follows:

	Fair Value Measurements December 31, 2013		
	Total Fair Value	Maturity Year 1	Years 2&3
	(in millions)		
Level 1	$—	$—	$—
Level 2	(16)	(10)	(6)
Level 3	—	—	—
Fair value of contracts outstanding at end of period	$(16)	$(10)	$(6)

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

Capital Requirements and Contractual Obligations

The construction program of the Company is currently estimated to be $2.5 billion for 2014, $2.4 billion for 2015, and $2.1 billion for 2016. Capital expenditures to comply with environmental statutes and regulations included in these estimated amounts are $543 million, $366 million, and $202 million for 2014, 2015, and 2016, respectively. These amounts include capital expenditures related to contractual purchase commitments for nuclear fuel and capital expenditures covered under long-term service agreements.

See FUTURE EARNINGS POTENTIAL – "Environmental Matters – Environmental Statutes and Regulations" for additional information.

The construction program is subject to periodic review and revision, and actual construction costs may vary from these estimates because of numerous factors. These factors include: changes in business conditions; changes in load projections; changes in environmental statutes and regulations; the outcome of any legal challenges to 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; Georgia PSC approvals; changes in the expected environmental compliance program; changes in legislation; the cost and efficiency of construction labor, equipment, and materials; project scope and design changes; storm impacts; and the cost of capital. In addition, there can be no assurance that costs related to capital expenditures will be fully recovered. See Note 3 to the financial statements under "Retail Regulatory Matters – Nuclear Construction" for additional information.

As a result of requirements by the NRC, the Company has established external trust funds for nuclear decommissioning costs. For additional information, see Note 1 to the financial statements under "Nuclear Decommissioning."

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

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

MANAGEMENT'S DISCUSSION AND ANALYSIS (continued)
Georgia Power Company 2013 Annual Report

Contractual Obligations

	2014	2015-2016	2017-2018	After 2018	Total
	(in millions)				
Long-term debt[a] —					
Principal	$—	$1,754	$720	$6,131	$8,605
Interest	298	577	510	4,280	5,665
Preferred and preference stock dividends[b]	17	35	35	—	87
Financial derivative obligations[c]	13	8	—	—	21
Operating leases[d]	26	33	15	11	85
Capital leases[d]	5	12	14	14	45
Purchase commitments —					
Capital[e]	2,290	4,052	—	—	6,342
Fuel[f]	1,713	2,486	1,535	5,373	11,107
Purchased power[g]	242	712	710	4,080	5,744
Other[h]	89	129	176	277	671
Trusts —					
Nuclear decommissioning[i]	2	11	11	115	139
Pension and other postretirement benefit plans[j]	34	65	—	—	99
Total	$4,729	$9,874	$3,726	$20,281	$38,610

(a) All amounts are reflected based on final maturity dates. The Company plans to continue 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, 2014, as reflected in the statements of capitalization. Fixed rates include, where applicable, the effects of interest rate derivatives employed to manage interest rate risk. Long-term debt excludes capital lease amounts (shown separately).

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

(c) For additional information, see Notes 1 and 11 to the financial statements.

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

(e) The Company provides estimated capital expenditures for a three-year period, including capital expenditures and compliance costs 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 separately. At December 31, 2013, 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.

(f) Includes commitments to purchase coal, nuclear fuel, and natural gas, as well as the related transportation and storage. In most cases, these contracts contain provisions for price escalation, minimum purchase levels, and other financial commitments. Natural gas purchase commitments are based on various indices at the time of delivery. Amounts reflected for natural gas purchase commitments have been estimated based on the New York Mercantile Exchange future prices at December 31, 2013.

(g) Estimated minimum long-term obligations for various PPA purchases from gas-fired, biomass, and wind-powered facilities. A total of $1.3 billion of biomass PPAs is contingent upon the counterparty meeting specified contract dates for posting collateral and commercial operation. See Note 3 to the financial statements under "Retail Regulatory Matters – Renewables Development" for additional information.

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

(i)

Projections of nuclear decommissioning trust fund contributions are based on the 2010 ARP for 2014 and on the 2013 ARP thereafter. See Note 1 to the financial statements under "Nuclear Decommissioning" for additional information.

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

Table of Contents Index to Financial Statements

Cautionary Statement Regarding Forward-Looking Statements

The Company's 2013 Annual Report contains forward-looking statements. Forward-looking statements include, among other things, statements concerning retail sales, retail rates, customer growth, economic recovery, fuel and environmental cost recovery and other rate actions, current and proposed environmental regulations and related estimated expenditures, access to sources of capital, projections for the qualified pension plan, postretirement benefit plan, and nuclear decommissioning trust fund contributions, financing activities, plans and estimated costs for new generation resources, completion dates of construction projects, filings with state and federal regulatory authorities, impact of the ATRA, estimated sales and purchases under new power sale and purchase agreements, and estimated construction and other 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 including regulation of water, coal combustion residuals, and emissions of sulfur, nitrogen, carbon, soot, particulate matter, hazardous air pollutants, including mercury, and other substances, and also changes in tax and other laws and regulations to which the Company is subject, as well as changes in application of existing laws and regulations;
- current and future litigation, regulatory investigations, proceedings, or inquiries, including the pending EPA civil action against the Company and Internal Revenue Service and state tax audits;
- the effects, extent, and timing of the entry of additional competition in the markets in which the Company operates;
- variations in demand for electricity, including those relating to weather, the general economy and recovery from the recent recession, population and business growth (and declines), the effects of energy conservation 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;
- ability to control costs and avoid cost overruns during the development and construction of facilities, which include the development and construction of facilities with designs that have not been finalized or previously constructed, including changes in labor costs and productivity factors, adverse weather conditions, shortages and inconsistent quality of equipment, materials, and labor, contractor or supplier delay or non-performance under construction or other agreements, delays associated with start-up activities, including major equipment failure, system integration, and operations, and/or unforeseen engineering problems;
- ability to construct facilities in accordance with the requirements of permits and licenses and to satisfy any operational and environmental performance standards, including the requirements of tax credits and other incentives;
- investment performance of the Company's employee and retiree benefit plans and nuclear decommissioning trust funds;
- advances in technology;
- state and federal rate regulations and the impact of pending and future rate cases and negotiations, including rate cases related to fuel and other cost recovery mechanisms;
- regulatory approvals and actions related to Plant Vogtle Units 3 and 4, including Georgia PSC approvals and NRC actions;
- the inherent risks involved in operating and constructing nuclear generating facilities, including environmental, health, regulatory, natural disaster, terrorism, or financial risks;
- internal restructuring or other restructuring options that may be pursued;
-

potential business strategies, including acquisitions or dispositions of assets or businesses, which cannot be assured to be completed or beneficial to the Company;
- the ability of counterparties of the Company to make payments as and when due and to perform as required;
- the ability to obtain new short- and long-term contracts with wholesale customers;
- the direct or indirect effect on the Company's business resulting from terrorist incidents and the threat of terrorist incidents, including cyber intrusion;

II-224

Table of Contents Index to Financial Statements

- interest rate fluctuations and financial market conditions and the results of financing efforts, including the Company's credit ratings;
- the impacts of any potential U.S. credit rating downgrade or other 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 benefits of the DOE loan guarantees;
- the ability of the Company to obtain additional generating capacity at competitive prices;
- catastrophic events such as fires, earthquakes, explosions, floods, hurricanes, droughts, pandemic health events such as influenzas, or other similar occurrences;
- the direct or indirect effects on the Company's business resulting from incidents affecting the U.S. electric grid or operation of generating resources;
- the effect of accounting pronouncements issued periodically by standard setting bodies; and
- other factors discussed elsewhere herein and in other reports (including the Form 10-K) filed by the Company from time to time with the SEC.

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

Table of Contents Index to Financial Statements

STATEMENTS OF INCOME
For the Years Ended December 31, 2013, 2012, and 2011
Georgia Power Company 2013 Annual Report

	2013	2012	2011
	(in millions)		
Operating Revenues:			
Retail revenues	$7,620	$7,362	$8,099
Wholesale revenues, non-affiliates	281	281	341
Wholesale revenues, affiliates	20	20	32
Other revenues	353	335	328
Total operating revenues	8,274	7,998	8,800
Operating Expenses:			
Fuel	2,307	2,051	2,789
Purchased power, non-affiliates	224	315	390
Purchased power, affiliates	660	666	713
Other operations and maintenance	1,654	1,644	1,777
Depreciation and amortization	807	745	715
Taxes other than income taxes	382	374	369
Total operating expenses	6,034	5,795	6,753
Operating Income	2,240	2,203	2,047
Other Income and (Expense):			
Allowance for equity funds used during construction	30	53	96
Interest expense, net of amounts capitalized	(361)	(366)	(343)
Other income (expense), net	5	(17)	(13)
Total other income and (expense)	(326)	(330)	(260)
Earnings Before Income Taxes	1,914	1,873	1,787
Income taxes	723	688	625
Net Income	1,191	1,185	1,162
Dividends on Preferred and Preference Stock	17	17	17
Net Income After Dividends on Preferred and Preference Stock	$1,174	$1,168	$1,145

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

STATEMENTS OF COMPREHENSIVE INCOME
For the Years Ended December 31, 2013, 2012, and 2011
Georgia Power Company 2013 Annual Report

	2013	2012	2011
	(in millions)		
Net Income	$1,191	$1,185	$1,162
Other comprehensive income (loss):			
Qualifying hedges:			
Reclassification adjustment for amounts included in net income, net of tax of $1, $1, and $2, respectively	2	2	2
Total other comprehensive income (loss)	2	2	2
Comprehensive Income	$1,193	$1,187	$1,164

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

STATEMENTS OF CASH FLOWS
For the Years Ended December 31, 2013, 2012, and 2011
Georgia Power Company 2013 Annual Report

	2013	2012	2011
	(in millions)		
Operating Activities:			
Net income	$1,191	$1,185	$1,162
Adjustments to reconcile net income to net cash provided from operating activities —			
Depreciation and amortization, total	979	912	867
Deferred income taxes	476	377	500
Allowance for equity funds used during construction	(30)	(53)	(96)
Retail fuel cost over recovery—long-term	(123)	123	—
Pension, postretirement, and other employee benefits	59	9	(29)
Other, net	37	(12)	(23)
Changes in certain current assets and liabilities —			
-Receivables	(58)	205	235
-Fossil fuel stock	250	(269)	(99)
-Prepaid income taxes	(17)	(7)	72
-Other current assets	40	(53)	(21)
-Accounts payable	67	(165)	44
-Accrued taxes	(14)	(76)	(36)
-Accrued compensation	(37)	(18)	7
-Retail fuel cost over-recovery—short-term	(49)	107	—
-Other current liabilities	(5)	30	49
Net cash provided from operating activities	2,766	2,295	2,632
Investing Activities:			
Property additions	(1,743)	(1,723)	(1,861)
Investment in restricted cash from pollution control bonds	(89)	(284)	—
Distribution of restricted cash from pollution control bonds	89	284	—
Nuclear decommissioning trust fund purchases	(706)	(852)	(1,845)
Nuclear decommissioning trust fund sales	705	850	1,841
Cost of removal, net of salvage	(59)	(82)	(42)
Change in construction payables, net of joint owner portion	(67)	(149)	123
Other investing activities	(20)	(17)	(7)
Net cash used for investing activities	(1,890)	(1,973)	(1,791)
Financing Activities:			
Increase (decrease) in notes payable, net	1,047	(513)	(61)
Proceeds —			
Capital contributions from parent company	37	42	214
Pollution control revenue bonds issuances and remarketings	194	284	604
Senior notes issuances	850	2,300	550
Other long-term debt issuances	—	—	250
Redemptions and repurchases —			
Pollution control revenue bonds	(298)	(284)	(339)
Senior notes	(1,775)	(850)	(427)
Other long-term debt	—	(250)	(303)
Long-term debt to affiliate trust	—	—	(206)

Payment of preferred and preference stock dividends	(17)	(17)	(17)
Payment of common stock dividends	(907)	(983)	(1,096)
Other financing activities	(22)	(19)	(5)
Net cash used for financing activities	(891)	(290)	(836)
Net Change in Cash and Cash Equivalents	(15)	32	5
Cash and Cash Equivalents at Beginning of Year	45	13	8
Cash and Cash Equivalents at End of Year	$30	$45	$13
Supplemental Cash Flow Information:			
Cash paid during the period for —			
Interest (net of $14, $21 and $37 capitalized, respectively)	$344	$337	$346
Income taxes (net of refunds)	298	312	54
Noncash transactions - accrued property additions at year-end	208	261	391

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

BALANCE SHEETS
At December 31, 2013 and 2012
Georgia Power Company 2013 Annual Report

Assets	2013	2012
	(in millions)	
Current Assets:		
Cash and cash equivalents	$30	$45
Receivables —		
Customer accounts receivable	512	484
Unbilled revenues	209	217
Joint owner accounts receivable	67	51
Other accounts and notes receivable	117	68
Affiliated companies	21	23
Accumulated provision for uncollectible accounts	(5)	(6)
Fossil fuel stock, at average cost	742	992
Materials and supplies, at average cost	409	452
Vacation pay	88	85
Prepaid income taxes	97	164
Other regulatory assets, current	66	72
Other current assets	54	104
Total current assets	2,407	2,751
Property, Plant, and Equipment:		
In service	30,132	29,244
Less accumulated provision for depreciation	10,970	10,431
Plant in service, net of depreciation	19,162	18,813
Other utility plant, net	240	263
Nuclear fuel, at amortized cost	523	497
Construction work in progress	3,500	2,893
Total property, plant, and equipment	23,425	22,466
Other Property and Investments:		
Equity investments in unconsolidated subsidiaries	46	45
Nuclear decommissioning trusts, at fair value	751	698
Miscellaneous property and investments	44	44
Total other property and investments	841	787
Deferred Charges and Other Assets:		
Deferred charges related to income taxes	718	733
Prepaid pension costs	118	—
Other regulatory assets, deferred	1,152	1,798
Other deferred charges and assets	246	268
Total deferred charges and other assets	2,234	2,799
Total Assets	$28,907	$28,803

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

Table of Contents Index to Financial Statements

BALANCE SHEETS
At December 31, 2013 and 2012
Georgia Power Company 2013 Annual Report

Liabilities and Stockholder's Equity	2013 (in millions)	2012
Current Liabilities:		
Securities due within one year	$5	$1,680
Notes payable	1,047	2
Accounts payable —		
Affiliated	417	417
Other	472	436
Customer deposits	246	237
Accrued taxes —		
Accrued income taxes	—	6
Other accrued taxes	321	260
Accrued interest	91	100
Accrued vacation pay	61	61
Accrued compensation	80	113
Liabilities from risk management activities	13	30
Other regulatory liabilities, current	17	73
Over recovered regulatory clause revenues, current	14	107
Other current liabilities	122	146
Total current liabilities	2,906	3,668
Long-Term Debt (See accompanying statements)	8,633	7,994
Deferred Credits and Other Liabilities:		
Accumulated deferred income taxes	5,200	4,861
Deferred credits related to income taxes	112	115
Accumulated deferred investment tax credits	203	208
Employee benefit obligations	542	950
Asset retirement obligations	1,210	1,097
Other cost of removal obligations	43	63
Other deferred credits and liabilities	201	308
Total deferred credits and other liabilities	7,511	7,602
Total Liabilities	19,050	19,264
Preferred Stock (See accompanying statements)	45	45
Preference Stock (See accompanying statements)	221	221
Common Stockholder's Equity (See accompanying statements)	9,591	9,273
Total Liabilities and Stockholder's Equity	$28,907	$28,803
Commitments and Contingent Matters (See notes)		

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

Table of Contents Index to Financial Statements

STATEMENTS OF CAPITALIZATION
At December 31, 2013 and 2012
Georgia Power Company 2013 Annual Report

	2013	2012	2013	2012
	(in millions)		(percent of total)	
Long-Term Debt:				
Long-term notes payable —				
Variable rates (0.58% to 0.63% at 1/1/13) due 2013	$—	$650		
Variable rates (0.57% to 0.65% at 1/1/14) due 2016	450	—		
1.30% to 6.00% due 2013	—	1,025		
0.625% to 5.25% due 2015	1,050	1,050		
3.00% due 2016	250	250		
5.70% due 2017	450	450		
5.40% due 2018	250	250		
2.85% to 8.20% due 2019-2048	4,475	4,175		
Total long-term notes payable	6,925	7,850		
Other long-term debt —				
Pollution control revenue bonds:				
0.80% to 5.75% due 2022-2049	818	919		
Variable rate (0.06% at 1/1/14) due 2016	4	4		
Variable rate (0.04% at 1/1/14) due 2018	20	20		
Variable rates (0.04% to 0.11% at 1/1/14) due 2022-2052	838	841		
Total other long-term debt	1,680	1,784		
Capitalized lease obligations	45	50		
Unamortized debt discount	(12)	(10)		
Total long-term debt (annual interest requirement — $298 million)	8,638	9,674		
Less amount due within one year	5	1,680		
Long-term debt excluding amount due within one year	8,633	7,994	46.7 %	45.6 %
Preferred and Preference Stock:				
Non-cumulative preferred stock				
$25 par value — 6.125%				
Authorized: 50,000,000 shares				
Outstanding: 1,800,000 shares	45	45		
Non-cumulative preference stock				
$100 par value — 6.50%				
Authorized: 15,000,000 shares				
Outstanding: 2,250,000 shares	221	221		
Total preferred and preference stock (annual dividend requirement — $17 million)	266	266	1.4	1.5
Common Stockholder's Equity:				
Common stock, without par value —				
Authorized: 20,000,000 shares				
Outstanding: 9,261,500 shares	398	398		
Paid-in capital	5,633	5,585		
Retained earnings	3,565	3,297		

Accumulated other comprehensive loss	(5)	(7)		
Total common stockholder's equity	9,591	9,273	51.9	52.9
Total Capitalization	$18,490	$17,533	100.0 %	100.0 %

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

Table of Contents Index to Financial Statements

STATEMENTS OF COMMON STOCKHOLDER'S EQUITY
For the Years Ended December 31, 2013, 2012, and 2011
Georgia Power Company 2013 Annual Report

	Number of Common Shares Issued (in millions)	Common Stock	Paid-In Capital	Retained Earnings	Accumulated Other Comprehensive Income (Loss)	Total
Balance at December 31, 2010	9	$398	$5,291	$3,063	$(11)	$8,741
Net income after dividends on preferred and preference stock	—	—	—	1,145	—	1,145
Capital contributions from parent company	—	—	231	—	—	231
Other comprehensive income (loss)	—	—	—	—	2	2
Cash dividends on common stock	—	—	—	(1,096)	—	(1,096)
Balance at December 31, 2011	9	398	5,522	3,112	(9)	9,023
Net income after dividends on preferred and preference stock	—	—	—	1,168	—	1,168
Capital contributions from parent company	—	—	63	—	—	63
Other comprehensive income (loss)	—	—	—	—	2	2
Cash dividends on common stock	—	—	—	(983)	—	(983)
Balance at December 31, 2012	9	398	5,585	3,297	(7)	9,273
Net income after dividends on preferred and preference stock	—	—	—	1,174	—	1,174
Capital contributions from parent company	—	—	48	—	—	48
Other comprehensive income (loss)	—	—	—	—	2	2
Cash dividends on common stock	—	—	—	(907)	—	(907)
Other	—	—	—	1	—	1
Balance at December 31, 2013	9	$398	$5,633	$3,565	$(5)	$9,591

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

NOTES TO FINANCIAL STATEMENTS
Georgia Power Company 2013 Annual Report

Index to the Notes to Financial Statements

Table of Contents Index to Financial Statements

NOTES (continued)
Georgia Power Company 2013 Annual Report

1. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES
General
Georgia Power Company (the Company) is a wholly-owned subsidiary of The Southern Company (Southern Company), which is the parent company of the Company and three other traditional operating companies, as well as Southern Power Company (Southern Power), Southern Company Services, Inc. (SCS), Southern Communications Services, Inc. (SouthernLINC Wireless), Southern Company Holdings, Inc. (Southern Holdings), Southern Nuclear Operating Company, Inc. (Southern Nuclear), and other direct and indirect subsidiaries. The traditional operating companies – the Company, Alabama Power Company (Alabama Power), Gulf Power Company (Gulf Power), and Mississippi Power Company – are vertically integrated utilities providing electric service in four Southeastern states. The Company operates as a vertically integrated utility providing electricity to retail customers within its traditional service area located within the State of Georgia and to wholesale customers in the Southeast. Southern Power constructs, acquires, owns, and manages generation assets, including renewable energy projects, and sells electricity at market-based rates in the wholesale market. 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. Southern Nuclear operates and provides services to the Southern Company system's nuclear power plants, including the Company's Plant Hatch and Plant Vogtle.
The equity method is used for subsidiaries in which the Company has significant influence but does not control.
The Company is subject to regulation by the Federal Energy Regulatory Commission (FERC) and the Georgia Public Service Commission (PSC). The Company follows generally accepted accounting principles (GAAP) in the U.S. and complies with the accounting policies and practices prescribed by its regulatory commissions. The preparation of financial statements in conformity with GAAP requires the use of estimates, and the actual results may differ from those estimates. Certain prior years' data presented in the financial statements have been reclassified to conform to the current year presentation.
Affiliate Transactions
The Company has an agreement with SCS under which the following services are rendered to the Company at direct or allocated cost: general and design engineering, operations, purchasing, accounting, finance and treasury, tax, information technology, marketing, auditing, insurance and pension administration, human resources, systems and procedures, digital wireless communications, and other services with respect to business and operations, construction management, and power pool transactions. Costs for these services amounted to $504 million in 2013, $540 million in 2012, and $550 million in 2011. Cost allocation methodologies used by SCS prior to the repeal of the Public Utility Holding Company Act of 1935, as amended, were approved by the U.S. Securities and Exchange Commission (SEC). Subsequently, additional cost allocation methodologies have been reported to the FERC and management believes they are reasonable. The FERC permits services to be rendered at cost by system service companies.
The Company has an agreement with Southern Nuclear under which the following nuclear-related services are rendered to the Company at cost: general executive and advisory services, general operations, management and technical services, administrative services including procurement, accounting, employee relations, systems and procedures services, strategic planning and budgeting services, and other services with respect to business, operations, and construction management. Costs for these services amounted to $555 million in 2013, $574 million in 2012, and $537 million in 2011.
The Company has entered into several power purchase agreements (PPA) with Southern Power for capacity and energy. Expenses associated with these PPAs were $136 million, $147 million, and $171 million in 2013, 2012, and 2011, respectively. Additionally, the Company had $15 million of prepaid capacity expenses included in deferred charges and other assets in the balance sheets at December 31, 2013 and 2012. See Note 7 under "Fuel and Purchased

Power Agreements" for additional information.
The Company has a joint ownership agreement with Gulf Power under which Gulf Power owns a 25% portion of Plant Scherer Unit 3. Under this agreement, the Company operates Plant Scherer Unit 3 and Gulf Power reimburses the Company for its 25% proportionate share of the related non-fuel expenses, which were $10 million in 2013, $7 million in 2012, and $7 million in 2011. See Note 4 for additional information.
The Company provides incidental services to and receives such services from other Southern Company subsidiaries which are generally minor in duration and amount. Except as described herein, the Company neither provided nor received any material services to or from affiliates in 2013, 2012, or 2011.

See Note 4 for information regarding the Company's ownership in and a PPA with Southern Electric Generating Company (SEGCO). SEGCO plans to add natural gas as the primary fuel source for its generating units in 2015. SEGCO has entered into a joint ownership agreement with Alabama Power, which owns and operates a generating unit adjacent to the SEGCO units, for the ownership of the gas pipeline. SEGCO will own 86% of the pipeline with the remaining 14% owned by Alabama Power.

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

Regulatory Assets and Liabilities

The Company is subject to 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.

NOTES (continued)
Georgia Power Company 2013 Annual Report

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

	2013	2012	Note
	(in millions)		
Retiree benefit plans	$691	$1,331	(a, k)
Deferred income tax charges	684	695	(b)
Deferred income tax charges — Medicare subsidy	38	43	(c)
Loss on reacquired debt	181	190	(d)
Asset retirement obligations	137	131	(b, k)
Fuel-hedging (realized and unrealized) losses	22	49	(e)
Vacation pay	88	85	(f, k)
Building leases	37	40	(g)
Cancelled construction projects	70	65	(h)
Remaining net book value of retired units	28	—	(i)
Other regulatory assets	86	100	(c)
Other cost of removal obligations	(58)	(94)	(b)
Deferred income tax credits	(112)	(115)	(b)
State income tax credits	—	(36)	(j)
Other regulatory liabilities	(6)	(13)	(e)
Total regulatory assets (liabilities), net	$1,886	$2,471	

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

(a) Recovered and amortized over the average remaining service period which may range up to 14 years. See Note 2 for additional information.

(b) Asset retirement and other cost of removal obligations and deferred income tax assets are recovered, and deferred income tax liabilities are amortized over the related property lives, which may range up to 70 years. Asset retirement and removal liabilities will be settled and trued up following completion of the related activities. At December 31, 2013, other cost of removal obligations included $43 million that will be amortized over the three-year period of January 2014 through December 2016 in accordance with the Company's Alternate Rate Plan for the years 2014 through 2016 (2013 ARP).

(c) Recorded and recovered or amortized as approved by the Georgia PSC over periods generally not exceeding nine years.

(d) Recovered over either the remaining life of the original issue or, if refinanced, over the remaining life of the new issue, which currently does not exceed 39 years.

(e) Fuel-hedging assets and liabilities are recorded over the life of the underlying hedged purchase contracts, which generally do not exceed two years. Upon final settlement, actual costs incurred are recovered through the Company's fuel cost recovery mechanism.

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

(g) See Note 6 under "Capital Leases." Recovered over the remaining lives of the buildings through 2026.

(h) Costs associated with construction of environmental controls that will not be completed as a result of unit retirements and amortized over nine years in accordance with the 2013 ARP.

(i) Amortization period over original remaining life beginning October 2013 through December 2022 as approved by the Georgia PSC in the 2013 ARP.

(j) Additional tax benefits resulting from the Georgia state income tax credit settlement that were amortized over a 21-month period that began in April 2012 and ended in December 2013, in accordance with a Georgia PSC order. See Note 5 under "Current and Deferred Income Taxes" for additional information.

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

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

Revenues

Wholesale capacity revenues are generally recognized on a levelized basis over the appropriate contract period. Energy and other revenues are recognized as services are provided. Unbilled revenues related to retail sales are accrued at the end of each fiscal period. Electric rates for the Company include provisions to adjust billings for fluctuations in fuel costs, the energy component of purchased power costs, and certain other costs. Revenues are adjusted for differences between the actual recoverable costs and amounts billed in current regulated rates.

NOTES (continued)
Georgia Power Company 2013 Annual Report

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

Fuel Costs

Fuel costs are expensed as the fuel is used. Fuel expense 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. See Note 3 under "Nuclear Fuel Disposal Costs" for additional information.

Income and Other Taxes

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

Federal investment tax credits (ITCs) utilized are deferred and amortized to income as a credit to reduce depreciation over the average life of the related property. State ITCs are recognized in the period in which the credits are claimed on the state income tax return. A portion of the ITCs available to reduce income taxes payable was not utilized currently and will be carried forward and utilized in future years.

In accordance with accounting standards related to the uncertainty in income taxes, the Company recognizes tax positions that are "more likely than not" of being sustained upon examination by the appropriate taxing authorities. See Note 5 under "Unrecognized Tax Benefits" for additional information.

Property, Plant, and Equipment

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

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

	2013	2012
	(in millions)	
Generation	$14,872	$14,567
Transmission	4,859	4,581
Distribution	8,620	8,373
General	1,753	1,695
Plant acquisition adjustment	28	28
Total plant in service	$30,132	$29,244

The cost of replacements of property, exclusive of minor items of property, is capitalized. The cost of maintenance, repairs, and replacement of minor items of property is charged to other operations and maintenance expenses as incurred or performed with the exception of certain generating plant maintenance costs. As mandated by the Georgia PSC, the Company defers and amortizes nuclear refueling outage costs over the unit's operating cycle. The refueling cycles are 18 and 24 months for Plant Vogtle Units 1 and 2 and Plant Hatch Units 1 and 2, respectively. Also, in accordance with a Georgia PSC order, the Company deferred the costs of certain significant inspection costs for the combustion turbine units at Plant McIntosh and amortized such costs over 10 years, which approximated the expected maintenance cycle of the units. All inspection costs were fully amortized in 2013.

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 2013, 2.9% in 2012, and 2.8% in 2011. Depreciation studies are conducted periodically to update the composite rates that are approved by the Georgia PSC and the FERC. Effective January 1, 2014, the Company's depreciation rates were revised by the Georgia PSC in connection with the 2013 ARP. When property subject to depreciation is retired or otherwise disposed of in the normal course of business, its original cost, together with the cost of removal, less salvage, is charged to accumulated depreciation. For other property dispositions, the applicable cost and accumulated depreciation are removed from the balance sheet accounts, and a gain or loss is recognized. Minor items of property included in the original cost of the plant are retired when the related property unit is retired.

NOTES (continued)
Georgia Power Company 2013 Annual Report

In 2009, the Georgia PSC approved an accounting order allowing the Company to amortize a portion of its regulatory liability related to other cost of removal obligations. Under the terms of the Company's Alternate Rate Plan for the years 2011 through 2013 (2010 ARP), the Company amortized approximately $31 million annually of the remaining regulatory liability related to other cost of removal obligations over the three years ended December 31, 2013. Under the terms of the 2013 ARP, an additional $43 million will be amortized ratably over the three years ending December 31, 2016.

Asset Retirement Obligations and Other Costs of Removal

Asset retirement obligations are computed as the present value of the 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. The Company has received accounting guidance from the Georgia PSC allowing the continued accrual of other future retirement costs for long-lived assets that the Company does not have a legal obligation to retire. Accordingly, the accumulated removal costs for these obligations are reflected in the balance sheets as a regulatory liability.

The asset retirement obligation liability relates to the decommissioning of the Company's nuclear facilities, which include the Company's ownership interests in Plant Hatch and Plant Vogtle Units 1 and 2, as well as various landfill sites, ash ponds, underground storage tanks, and asbestos removal. The Company also has identified retirement obligations related to certain transmission and distribution facilities, including the disposal of polychlorinated biphenyls in certain transformers; leasehold improvements; equipment on customer property; and property associated with the Company's rail lines and natural gas pipelines. However, liabilities for the removal of these assets have not been recorded because the settlement timing for the retirement obligations related to these assets is indeterminable and, therefore, the fair value of the retirement obligations cannot be reasonably estimated. A liability for these asset retirement obligations will be recognized when sufficient information becomes available to support a reasonable estimation of the asset retirement obligation. The Company will continue to recognize in the statements of income the allowed removal costs in accordance with its regulatory treatment. Any difference between costs recognized in accordance with accounting standards related to asset retirement and environmental obligations and those reflected in rates are recognized as either a regulatory asset or liability in the balance sheets as ordered by the Georgia PSC. See "Nuclear Decommissioning" herein for additional information on amounts included in rates.

Details of the asset retirement obligations included in the balance sheets are as follows:

	2013	2012
	(in millions)	
Balance at beginning of year	$1,105	$757
Liabilities incurred	2	24
Liabilities settled	(13)	(15)
Accretion	55	72
Cash flow revisions	73	267
Balance at end of year	$1,222	$1,105

The increase in cash flow revisions is related to updated estimates for ash ponds in connection with the retirement of certain coal-fired generating units and revisions to the nuclear decommissioning asset retirement obligations based on the latest decommissioning study.

Nuclear Decommissioning

The U.S. Nuclear Regulatory Commission (NRC) requires licensees of commercial nuclear power reactors to establish a plan for providing reasonable assurance of funds for future decommissioning. The Company has external trust funds (Funds) to comply with the NRC's regulations. Use of the Funds is restricted to nuclear decommissioning activities. The Funds are managed and invested in accordance with applicable requirements of various regulatory bodies, including the NRC, the FERC, and the Georgia PSC, as well as the Internal Revenue Service (IRS). The Funds are required to be held by one or more trustees with an individual net worth of at least $100 million. The FERC requires the Funds' managers to exercise the standard of care in investing that a "prudent investor" would use in the same circumstances. The FERC regulations also require that the Funds' managers may not invest in any securities of the utility for which it manages funds or its affiliates, except for investments tied to market indices or other mutual funds. While the Company is allowed to prescribe an overall investment policy to the Funds' managers, the Company and its affiliates are not allowed to engage in the day-to-day management of the Funds or to mandate individual investment decisions. Day-to-day management of the investments in the Funds is delegated to unrelated third party managers with oversight by the management of the Company. The Funds' managers are authorized, within certain investment guidelines, to actively buy and sell securities at their own discretion in order to maximize the return on the Funds' investments. The Funds are invested in a tax-efficient manner in a diversified mix of equity and fixed income securities and are reported as trading securities.

The Company records the investment securities held in the Funds at fair value, as discussed 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 asset retirement obligations in the balance sheets and are not included in net income or OCI. Fair value adjustments and realized gains and losses are determined on a specific identification basis.

The Funds participate in a securities lending program through the managers of the Funds. Under this program, the Funds' investment securities are loaned to institutional investors for a fee. Securities so loaned are fully collateralized by cash, letters of credit, and securities issued or guaranteed by the U.S. government, its agencies, and the instrumentalities. As of December 31, 2013 and 2012, approximately $32 million and $91 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 $33 million and $93 million at December 31, 2013 and 2012, 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, 2013, investment securities in the Funds totaled $751 million, consisting of equity securities of $330 million, debt securities of $397 million, and $24 million of other securities. At December 31, 2012, investment securities in the Funds totaled $698 million, consisting of equity securities of $280 million, debt securities of $408 million, and $10 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 $705 million, $850 million, and $1.8 billion in 2013, 2012, and 2011, respectively, all of which were reinvested. For 2013, fair value increases, including reinvested interest and dividends and excluding the Funds' expenses, were $61 million, of which $34 million related to unrealized gains on securities held in the Funds at December 31, 2013. For 2012, fair value increases, including reinvested interest and dividends and excluding the Funds' expenses, were $67 million, of which $25 million related to unrealized gains on securities held in the Funds at December 31, 2012. For 2011, fair value increases, including reinvested interest and dividends and excluding the Funds' expenses, were $23 million, of which $9 million related to unrealized losses on securities held in the Funds at December 31, 2011. 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 and purpose for which the securities were acquired.

The NRC's minimum external funding requirements are based on a generic estimate of the cost to decommission only the radioactive portions of a nuclear unit based on the size and type of reactor. The Company has filed plans with the NRC designed to ensure that, over time, the deposits and earnings of the Funds will provide the minimum funding amounts prescribed by the NRC.

NOTES (continued)
Georgia Power Company 2013 Annual Report

Site study cost is the estimate to decommission a specific facility as of the site study year. The decommissioning cost estimates are based on prompt dismantlement and removal of the plant from service. The actual decommissioning costs may vary from these estimates because of changes in the assumed date of decommissioning, changes in NRC requirements, or changes in the assumptions used in making these estimates. The estimated costs of decommissioning are based on the most current study performed in 2012. The site study costs and external trust funds for decommissioning as of December 31, 2013 based on the Company's ownership interests were as follows:

	Plant Hatch	Plant Vogtle Units 1 and 2
Decommissioning periods:		
Beginning year	2034	2047
Completion year	2068	2072
	(in millions)	
Site study costs:		
Radiated structures	$549	$453
Spent fuel management	131	115
Non-radiated structures	51	76
Total site study costs	$731	$644
External trust funds	$469	$277

For ratemaking purposes, the Company's decommissioning costs are based on the NRC generic estimate to decommission the radioactive portion of the facilities and the site study estimate for spent fuel management as of 2012. The Georgia PSC approved annual decommissioning costs for ratemaking of $2 million annually for Plant Hatch for 2011 through 2013. Under the 2013 ARP, the annual decommissioning cost through 2016 for ratemaking is $4 million and $2 million for Plant Hatch and Plant Vogtle Units 1 and 2, respectively. Significant assumptions used to determine the costs for ratemaking include an estimated inflation rate of 2.4% and an estimated trust earnings rate of 4.4%. The Company expects the Georgia PSC to periodically review and adjust, if necessary, the amounts collected in rates for nuclear decommissioning costs.

Allowance for Funds Used During Construction

In accordance with regulatory treatment, the Company records allowance for funds used during construction (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. For the years 2013, 2012, and 2011, the average AFUDC rates were 5.3%, 6.8%, and 7.5%, respectively, and AFUDC capitalized was $44 million, $75 million, and $134 million, respectively. AFUDC, net of income taxes, was 3.3%, 5.7%, and 10.4% of net income after dividends on preferred and preference stock for 2013, 2012, and 2011, respectively. See Note 3 under "Retail Regulatory Matters – Nuclear Construction" for additional information on the inclusion of construction costs related to the construction of two new nuclear generating units at Plant Vogtle (Plant Vogtle Units 3 and 4) in rate base effective January 1, 2011.

Impairment of Long-Lived Assets and Intangibles

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

Storm Damage Recovery

The Company defers and recovers certain costs related to damages from major storms as mandated by the Georgia PSC. Under the 2010 ARP, the Company accrued $18 million annually that was recoverable through base rates. At December 31, 2013, the Company's regulatory asset related to storm damage was $37 million, with approximately $30 million included in other regulatory assets, current and approximately $7 million included as other regulatory assets, deferred. Beginning January 1, 2014, the Company is accruing $30 million annually under the 2013 ARP. The Company expects the Georgia PSC to periodically review and adjust, if necessary, the amounts collected in rates for storm damage costs.

Environmental Remediation Recovery

The Company maintains a reserve for environmental remediation as mandated by the Georgia PSC. On December 17, 2013, the Georgia PSC approved the 2013 ARP including the recovery of approximately $2 million annually through the environmental compliance cost recovery (ECCR) tariff from 2014 through 2016. The Company recovered approximately $3 million annually through the ECCR tariff from 2011 through 2013 under the 2010 ARP. The Company recognizes a liability for environmental remediation costs only when it determines a loss is probable and reduces the reserve as expenditures are incurred. Any difference between the liabilities accrued and cost recovered through rates is deferred as a regulatory asset or liability. The annual recovery amount is expected to be reviewed by the Georgia PSC and adjusted in future regulatory proceedings. As a result of this regulatory treatment, environmental remediation liabilities generally are not expected to have a material impact on the Company's financial statements. As of December 31, 2013, the balance of the environmental remediation liability was $18 million, with approximately $2 million included in other regulatory assets, current and approximately $9 million included as other regulatory assets, deferred. See Note 3 under "Environmental Matters – Environmental Remediation" for additional information.

Cash and Cash Equivalents

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

Materials and Supplies

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

Fuel Inventory

Fuel inventory includes the average cost of coal, natural gas, and oil, as well as transportation and emissions allowances. Fuel is charged to inventory when purchased and then expensed, at weighted average cost, as used and recovered by the Company through fuel cost recovery rates approved by the Georgia PSC. Emissions allowances granted by the U.S. Environmental Protection Agency (EPA) are included in inventory at zero cost.

Financial Instruments

The Company uses derivative financial instruments to limit exposure to fluctuations in interest rates, the prices of certain fuel purchases, and electricity purchases and sales. All derivative financial instruments are recognized as either assets or liabilities (included in "Other" or shown separately as "Risk Management Activities") and are measured at fair value. See Note 10 for additional information. Substantially all of the Company's bulk energy purchases and sales contracts that meet the definition of a derivative are excluded from fair value accounting requirements because they qualify for the "normal" scope exception, and are accounted for under the accrual method. Other derivative contracts qualify as cash flow hedges of anticipated transactions or are recoverable through the Georgia PSC-approved fuel-hedging program. This results 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 are marked to market through current period income and are recorded on a net basis in the statements of income. See Note 11 for additional information.

The Company does not offset fair value amounts recognized for multiple derivative instruments executed with the same counterparty under a master netting arrangement. Additionally, the Company had no outstanding collateral repayment obligations or rights to reclaim collateral arising from derivative instruments recognized at December 31, 2013.

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

Comprehensive Income

The objective of comprehensive income is to report a measure of all changes in common stock equity of an enterprise that result from transactions and other economic events of the period other than transactions with owners. Comprehensive income consists of net income, changes in the fair value of qualifying cash flow hedges, and reclassifications for amounts included in net income.

NOTES (continued)
Georgia Power Company 2013 Annual Report

2. RETIREMENT BENEFITS

The Company has a defined benefit, trusteed, pension plan covering substantially all employees. This qualified pension plan is funded in accordance with requirements of the Employee Retirement Income Security Act of 1974, as amended (ERISA). No contributions to the qualified pension plan were made during 2013. No mandatory contributions to the qualified pension plan are anticipated for the year ending December 31, 2014. The Company also provides certain defined benefit pension plans for a selected group of management and highly compensated employees. Benefits under these non-qualified pension plans are funded on a cash basis. In addition, the Company provides certain medical care and life insurance benefits for retired employees through other postretirement benefit plans. The Company funds its other postretirement trusts to the extent required by the Georgia PSC and the FERC. For the year ending December 31, 2014, other postretirement trust contributions are expected to total approximately $13 million.

Actuarial Assumptions

The weighted average rates assumed in the actuarial calculations used to determine both the benefit obligations as of the measurement date and the net periodic costs for the pension and other postretirement benefit plans for the following year are presented below. Net periodic benefit costs were calculated in 2010 for the 2011 plan year using discount rates for the pension plans and the other postretirement benefit plans of 5.52% and 5.40%, respectively, and an annual salary increase of 3.84%.

	2013	2012	2011
Discount rate:			
Pension plans	5.02 %	4.27 %	4.98 %
Other postretirement benefit plans	4.85	4.04	4.87
Annual salary increase	3.59	3.59	3.84
Long-term return on plan assets:			
Pension plans	8.20	8.20	8.45
Other postretirement benefit plans	6.74	7.24	7.25

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

An additional assumption used in measuring the accumulated other postretirement benefit obligations (APBO) was a weighted average medical care cost trend rate of 7.00% for 2014, decreasing gradually to 5.00% through the year 2021 and remaining at that level thereafter. 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, 2013 as follows:

	1 Percent Increase	1 Percent Decrease
	(in millions)	
Benefit obligation	$51	$(43)
Service and interest costs	2	(2)

Table of Contents Index to Financial Statements

NOTES (continued)
Georgia Power Company 2013 Annual Report

Pension Plans

The total accumulated benefit obligation for the pension plans was $2.9 billion at December 31, 2013 and $3.1 billion at December 31, 2012. Changes in the projected benefit obligations and the fair value of plan assets during the plan years ended December 31, 2013 and 2012 were as follows:

	2013	2012
	(in millions)	
Change in benefit obligation		
Benefit obligation at beginning of year	$3,312	$2,909
Service cost	69	60
Interest cost	138	141
Benefits paid	(141)	(136)
Actuarial (gain) loss	(262)	338
Balance at end of year	3,116	3,312
Change in plan assets		
Fair value of plan assets at beginning of year	2,827	2,575
Actual return on plan assets	387	377
Employer contributions	12	11
Benefits paid	(141)	(136)
Fair value of plan assets at end of year	3,085	2,827
Accrued liability	$(31)	$(485)

At December 31, 2013, the projected benefit obligations for the qualified and non-qualified pension plans were $3.0 billion and $148 million, respectively. All pension plan assets are related to the qualified pension plan.

Amounts recognized in the balance sheets at December 31, 2013 and 2012 related to the Company's pension plans consist of the following:

	2013	2012
	(in millions)	
Prepaid pension costs	$118	$—
Other regulatory assets, deferred	610	1,132
Current liabilities, other	(12)	(11)
Employee benefit obligations	(137)	(474)

Presented below are the amounts included in regulatory assets at December 31, 2013 and 2012 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 2014.

	2013	2012	Estimated Amortization in 2014
	(in millions)		
Prior service cost	$26	$37	$10
Net (gain) loss	584	1,095	41
Regulatory assets	$610	$1,132	

NOTES (continued)
Georgia Power Company 2013 Annual Report

The changes in the balance of regulatory assets related to the defined benefit pension plans for the years ended December 31, 2013 and 2012 are presented in the following table:

	2013	2012
	(in millions)	
Regulatory assets:		
Beginning balance	$1,132	$995
Net (gain) loss	(438)	182
Reclassification adjustments:		
Amortization of prior service costs	(10)	(12)
Amortization of net gain (loss)	(74)	(33)
Total reclassification adjustments	(84)	(45)
Total change	(522)	137
Ending balance	$610	$1,132

Components of net periodic pension cost (income) were as follows:

	2013	2012	2011
	(in millions)		
Service cost	$69	$60	$57
Interest cost	138	141	144
Expected return on plan assets	(212)	(221)	(234)
Recognized net loss	74	33	6
Net amortization	10	12	12
Net periodic pension cost (income)	$79	$25	$(15)

Net periodic pension cost (income) 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, 2013, estimated benefit payments were as follows:

	Benefit Payments
	(in millions)
2014	$154
2015	161
2016	167
2017	175
2018	181
2019 to 2023	995

Table of Contents Index to Financial Statements

NOTES (continued)
Georgia Power Company 2013 Annual Report

Other Postretirement Benefits
Changes in the APBO and in the fair value of plan assets during the plan years ended December 31, 2013 and 2012 were as follows:

	2013	2012
	(in millions)	
Change in benefit obligation		
Benefit obligation at beginning of year	$800	$774
Service cost	7	7
Interest cost	31	37
Benefits paid	(45)	(46)
Actuarial (gain) loss	(73)	25
Retiree drug subsidy	3	3
Balance at end of year	723	800
Change in plan assets		
Fair value of plan assets at beginning of year	382	365
Actual return on plan assets	56	43
Employer contributions	11	17
Benefits paid	(42)	(43)
Fair value of plan assets at end of year	407	382
Accrued liability	$(316)	$(418)

Amounts recognized in the balance sheets at December 31, 2013 and 2012 related to the Company's other postretirement benefit plans consist of the following:

	2013	2012
	(in millions)	
Other regulatory assets, deferred	$69	$187
Employee benefit obligations	(316)	(418)

Presented below are the amounts included in regulatory assets at December 31, 2013 and 2012 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 2014.

	2013	2012	Estimated Amortization in 2014
	(in millions)		
Prior service cost	$(4)	$(4)	$—
Net (gain) loss	73	186	2
Transition obligation	—	5	—
Regulatory assets	$69	$187	

Table of Contents Index to Financial Statements

NOTES (continued)
Georgia Power Company 2013 Annual Report

The changes in the balance of regulatory assets related to the other postretirement benefit plans for the plan years ended December 31, 2013 and 2012 are presented in the following table:

	2013	2012
	(in millions)	
Regulatory assets:		
Beginning balance	$187	$186
Net (gain) loss	(106)	11
Reclassification adjustments:		
Amortization of transition obligation	(4)	(6)
Amortization of prior service costs	—	—
Amortization of net gain (loss)	(8)	(4)
Total reclassification adjustments	(12)	(10)
Total change	(118)	1
Ending balance	$69	$187

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

	2013	2012	2011
	(in millions)		
Service cost	$7	$7	$7
Interest cost	31	37	41
Expected return on plan assets	(24)	(29)	(30)
Net amortization	12	10	11
Net periodic postretirement benefit cost	$26	$25	$29

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)		
2014	$49	$(4)	$45
2015	50	(4)	46
2016	53	(5)	48
2017	54	(5)	49
2018	58	(6)	52
2019 to 2023	287	(30)	257

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.

Table of Contents Index to Financial Statements

NOTES (continued)
Georgia Power Company 2013 Annual Report

The composition of the Company's pension plan and other postretirement benefit plan assets as of December 31, 2013 and 2012, along with the targeted mix of assets for each plan, is presented below:

	Target		2013		2012	
Pension plan assets:						
Domestic equity	26	%	31	%	28	%
International equity	25		25		24	
Fixed income	23		23		27	
Special situations	3		1		1	
Real estate investments	14		14		13	
Private equity	9		6		7	
Total	100	%	100	%	100	%
Other postretirement benefit plan assets:						
Domestic equity	41	%	36	%	34	%
International equity	21		30		27	
Domestic fixed income	24		21		27	
Global fixed income	8		8		7	
Special situations	1		—		—	
Real estate investments	3		3		3	
Private equity	2		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, 2013 and 2012. 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.

Table of Contents Index to Financial Statements

NOTES (continued)
Georgia Power Company 2013 Annual Report

The fair values of pension plan assets as of December 31, 2013 and 2012 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			
As of December 31, 2013:	Quoted Prices in Active Markets for Identical Assets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)	Total
	(in millions)			
Assets:				
Domestic equity*	$506	$296	$—	$802
International equity*	389	359	—	748
Fixed income:				
U.S. Treasury, government, and agency bonds	—	212	—	212
Mortgage- and asset-backed securities	—	55	—	55
Corporate bonds	—	346	—	346
Pooled funds	—	166	—	166
Cash equivalents and other	—	79	—	79
Real estate investments	92	—	353	445
Private equity	—	—	202	202
Total	$987	$1,513	$555	$3,055
Liabilities:				
Derivatives	—	(1)	—	(1)
Total	$987	$1,512	$555	$3,054

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

NOTES (continued)
Georgia Power Company 2013 Annual Report

As of December 31, 2012:	Fair Value Measurements Using Quoted Prices in Active Markets for Identical Assets (Level 1) (in millions)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)	Total
Assets:				
Domestic equity*	$413	$238	$—	$651
International equity*	324	348	—	672
Fixed income:				
U.S. Treasury, government, and agency bonds	—	183	—	183
Mortgage- and asset-backed securities	—	45	—	45
Corporate bonds	—	312	1	313
Pooled funds	—	142	—	142
Cash equivalents and other	2	195	—	197
Real estate investments	92	—	299	391
Private equity	—	—	211	211
Total	$831	$1,463	$511	$2,805

* 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.

Changes in the fair value measurement of the Level 3 items in the pension plan assets valued using significant unobservable inputs for the years ended December 31, 2013 and 2012 were as follows:

	2013 Real Estate Investments (in millions)	Private Equity	2012 Real Estate Investments	Private Equity
Beginning balance	$299	$211	$296	$220
Actual return on investments:				
Related to investments held at year end	25	3	2	—
Related to investments sold during the year	10	17	1	2
Total return on investments	35	20	3	2
Purchases, sales, and settlements	19	(29)	—	(11)
Ending balance	$353	$202	$299	$211

Table of Contents Index to Financial Statements

NOTES (continued)
Georgia Power Company 2013 Annual Report

The fair values of other postretirement benefit plan assets as of December 31, 2013 and 2012 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			
As of December 31, 2013:	Quoted Prices in Active Markets for Identical Assets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)	Total
	(in millions)			
Assets:				
Domestic equity*	$74	$25	$—	$99
International equity*	12	57	—	69
Fixed income:				
U.S. Treasury, government, and agency bonds	—	7	—	7
Mortgage- and asset-backed securities	—	2	—	2
Corporate bonds	—	11	—	11
Pooled funds	—	34	—	34
Cash equivalents and other	—	6	—	6
Trust-owned life insurance	—	158	—	158
Real estate investments	3	—	11	14
Private equity	—	—	6	6
Total	$89	$300	$17	$406

* 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.

Table of Contents Index to Financial Statements

NOTES (continued)
Georgia Power Company 2013 Annual Report

As of December 31, 2012:	Fair Value Measurements Using Quoted Prices in Active Markets for Identical Assets (Level 1) (in millions)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)	Total
Assets:				
Domestic equity*	$65	$27	$—	$92
International equity*	10	51	—	61
Fixed income:				
U.S. Treasury, government, and agency bonds	—	6	—	6
Mortgage- and asset-backed securities	—	1	—	1
Corporate bonds	—	10	—	10
Pooled funds	—	32	—	32
Cash equivalents and other	—	18	—	18
Trust-owned life insurance	—	142	—	142
Real estate investments	3	—	10	13
Private equity	—	—	7	7
Total	$78	$287	$17	$382

* 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.

Changes in the fair value measurement of the Level 3 items in the other postretirement benefit plan assets valued using significant unobservable inputs for the years ended December 31, 2013 and 2012 were as follows:

	2013 Real Estate Investments (in millions)	Private Equity	2012 Real Estate Investments	Private Equity
Beginning balance	$10	$7	$9	$7
Actual return on investments:				
Related to investments held at year end	1	—	1	—
Related to investments sold during the year	—	—	—	—
Total return on investments	1	—	1	—
Purchases, sales, and settlements	—	(1)	—	—
Ending balance	$11	$6	$10	$7

Employee Savings Plan

The Company also sponsors a 401(k) defined contribution plan covering substantially all employees. The Company provides an 85% matching contribution on up to 6% of an employee's base salary. Total matching contributions made to the plan for 2013, 2012, and 2011 were $24 million, $24 million, and $24 million, respectively.

3. CONTINGENCIES AND REGULATORY MATTERS

General Litigation Matters

The Company is subject to certain claims and legal actions arising in the ordinary course of business. In addition, the Company's business activities are subject to extensive governmental regulation related to public health and the environment, such as regulation of air emissions and water discharges. Litigation over environmental issues and claims of various types, including property damage, personal injury, common law nuisance, and citizen enforcement of environmental requirements such as air quality and water standards, has increased generally throughout the U.S. In particular, personal injury, property damage, and other

NOTES (continued)
Georgia Power Company 2013 Annual Report

claims for damages alleged to have been caused by carbon dioxide and other emissions, coal combustion residuals, and alleged exposure to hazardous materials, and/or requests for injunctive relief in connection with such matters, have become more frequent. The ultimate outcome of such pending or potential litigation against the Company cannot be predicted at this time; however, for current proceedings not specifically reported herein, management does not anticipate that the ultimate liabilities, if any, arising from such current proceedings would have a material effect on the Company's financial statements.

Environmental Matters

New Source Review Actions

As part of a nationwide enforcement initiative against the electric utility industry which began in 1999, the EPA brought civil enforcement actions in federal district court against the Company alleging violations of the New Source Review provisions of the Clean Air Act at certain coal-fired electric generating units, including a unit co-owned by Gulf Power. These civil actions seek penalties and injunctive relief, including orders requiring installation of the best available control technologies at the affected units. The case against the Company (including claims related to a unit co-owned by Gulf Power) has been administratively closed in the U.S. District Court for the Northern District of Georgia since 2001.

The Company believes it complied with applicable laws and regulations in effect at the time the work in question took place. The Clean Air Act authorizes maximum civil penalties of $25,000 to $37,500 per day, per violation, depending on the date of the alleged violation. An adverse outcome could require substantial capital expenditures that cannot be determined at this time and could possibly require payment of substantial penalties. Such expenditures could affect future results of operations, cash flows, and financial condition if such costs are not recovered through regulated rates. The ultimate outcome of this matter cannot be determined at this time.

Environmental Remediation

The Company must comply with environmental laws and regulations that cover the handling and disposal of waste and releases of hazardous substances. Under these various laws and regulations, the Company may also incur substantial costs to clean up properties. See Note 1 under "Environmental Remediation Recovery" for additional information.

The Company 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 (NPL). The parties have completed the removal of wastes from the Brunswick site as ordered by the EPA. Additional cleanup and claims for recovery of natural resource damages at this site or for the assessment and potential cleanup of other sites are anticipated.

The Company and numerous other entities have been designated by the EPA as PRPs at the Ward Transformer Superfund site located in Raleigh, North Carolina. In 2011, the EPA issued a Unilateral Administrative Order (UAO) to the Company and 22 other parties, ordering specific remedial action of certain areas at the site. Later in 2011, the Company filed a response with the EPA stating it has sufficient cause to believe it is not a liable party under CERCLA. The EPA notified the Company in 2011 that it is considering enforcement options against the Company and other non-complying UAO recipients. If the EPA pursues enforcement actions and the court determines that a respondent failed to comply with the UAO without sufficient cause, the EPA may also seek civil penalties of up to $37,500 per day for the violation and punitive damages of up to three times the costs incurred by the EPA as a result of the party's failure to comply with the UAO.

In addition to the EPA's action at this site, the Company, along with many other parties, was sued in a private action by several existing PRPs for cost recovery related to the removal action. On February 1, 2013, the U.S. District Court for the Eastern District of North Carolina Western Division granted the Company's summary judgment motion, ruling that the Company has no liability in the private action. On May 10, 2013, the plaintiffs appealed the U.S. District Court for the Eastern District of North Carolina Western Division's order to the U.S. Court of Appeals for the Fourth

Circuit.
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 the regulatory recovery mechanisms described in Note 1 under "Environmental Remediation Recovery," these matters are not expected to have a material impact on the Company's financial statements.

Nuclear Fuel Disposal Costs

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

As a result of its first lawsuit, the Company recovered approximately $27 million, based on its ownership interests, representing the vast majority of the Company's direct costs of the expansion of spent nuclear fuel storage facilities at Plant Hatch and Plant Vogtle Units 1 and 2 from 1998 through 2004. The proceeds were received in July 2012 and credited to the Company accounts where the original costs were charged and were used to reduce rate base, fuel, and cost of service for the benefit of customers.

In 2008, the Company filed a second lawsuit against the U.S. government for the costs of continuing to store spent nuclear fuel at Plant Hatch and Plant Vogtle Units 1 and 2. Damages are being sought for the period from January 1, 2005 through December 31, 2010. 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, 2013 for any potential recoveries from the second lawsuit. The final outcome of this matter cannot be determined at this time; however, no material impact on the Company's net income is expected as a significant portion of any damage amounts collected from the government is expected to be credited to the Company accounts where the original costs were charged and used to reduce rate base, fuel, and cost of service for the benefit of customers.

An on-site dry storage facility at Plant Vogtle Units 1 and 2 began operation in October 2013. At Plant Hatch, an on-site dry spent fuel storage facility is also operational. Facilities at both plants can be expanded to accommodate spent fuel through the expected life of each plant.

Retail Regulatory Matters

Rate Plans

In 2010, the Georgia PSC approved the 2010 ARP, which resulted in base rate increases of approximately $562 million, $17 million, $125 million, and $74 million effective January 1, 2011, January 1, 2012, April 1, 2012, and January 1, 2013, respectively.

On December 17, 2013, the Georgia PSC voted to approve the 2013 ARP. The 2013 ARP reflects the settlement agreement among the Company, the Georgia PSC's Public Interest Advocacy Staff, and 11 of the 13 intervenors, which was filed with the Georgia PSC on November 18, 2013.

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

Under the 2013 ARP, the following additional rate adjustments will be made to the Company's tariffs in 2015 and 2016 based on annual compliance filings to be made at least 90 days prior to the effective date of the tariffs:

- Effective January 1, 2015 and 2016, the traditional base tariff rates will increase by an estimated $101 million and $36 million, respectively, to recover additional generation capacity-related costs;
- Effective January 1, 2015 and 2016, the ECCR tariff will increase by an estimated $76 million and $131 million, respectively, to recover additional environmental compliance costs;
- Effective January 1, 2015, the DSM tariffs will increase by an estimated $6 million and decrease by an estimated $1 million effective January 1, 2016; and
- The MFF tariff will increase consistent with these adjustments.

The Company currently estimates these adjustments will result in base revenue increases of approximately $187 million in 2015 and $170 million in 2016. The estimated traditional base tariff rate increases for 2015 and 2016 do not include additional Qualifying Facility (QF) PPA expenses; however, compliance filings will include QF PPA expenses for those facilities that are projected to provide capacity to the Company during the following year.

Under the 2013 ARP, the Company's retail return on common equity (ROE) is set at 10.95%, and earnings are evaluated against a retail ROE range of 10.00% to 12.00%. Two-thirds of any earnings above 12.00% will be directly refunded to customers, with the remaining one-third retained by the Company. There will be no recovery of any earnings shortfall below 10.00% on an actual basis. However, if at any time during the term of the 2013 ARP, the Company projects that its retail earnings will be below 10.00% for any calendar year, it may petition the Georgia PSC for implementation of the Interim Cost Recovery (ICR) tariff that would be used to adjust the Company's earnings back to a 10.00% retail ROE. The Georgia PSC would have 90 days to rule on the Company's request. The ICR tariff will expire at the earlier of January 1, 2017 or the end of the calendar year in which the

NOTES (continued)
Georgia Power Company 2013 Annual Report

ICR tariff becomes effective. In lieu of requesting implementation of an ICR tariff, or if the Georgia PSC chooses not to implement the ICR tariff, the Company may file a full rate case.
Except as provided above, the Company will not file for a general base rate increase while the 2013 ARP is in effect. The Company is required to file a general 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 Plans
On January 31, 2013, the Company filed its triennial Integrated Resource Plan (2013 IRP). The filing included the Company's request to decertify 16 coal- and oil-fired units totaling 2,093 megawatts (MWs). Several factors, including the cost to comply with existing and future environmental regulations, recent and forecasted economic conditions, and lower natural gas prices, contributed to the decision to close these units.
On April 17, 2013, the Georgia PSC approved the decertification of Plant Bowen Unit 6 (32 MWs), which was retired on April 25, 2013. On September 30, 2013, Plant Branch Unit 2 (319 MWs) was retired as approved by the Georgia PSC in the 2011 Integrated Resource Plan Update (2011 IRP Update) in order to comply with the State of Georgia's Multi-Pollutant Rule.
On July 11, 2013, the Georgia PSC approved the Company's request to decertify and retire Plant Boulevard Units 2 and 3 (28 MWs) effective July 17, 2013. Plant Branch Units 3 and 4 (1,016 MWs), Plant Yates Units 1 through 5 (579 MWs), and Plant McManus Units 1 and 2 (122 MWs) will be decertified and retired by April 16, 2015, the compliance date of the Mercury and Air Toxics Standards (MATS) rule. The decertification date of Plant Branch Unit 1 was extended from December 31, 2013 as specified in the final order in the 2011 IRP Update to coincide with the decertification date of Plant Branch Units 3 and 4. The decertification and retirement of Plant Kraft Units 1 through 4 (316 MWs) was also approved and will be effective by April 16, 2016, based on a one-year extension of the MATS rule compliance date that was approved by the State of Georgia Environmental Protection Division on September 10, 2013 to allow for necessary transmission system reliability improvements.
Additionally, the Georgia PSC approved the Company's proposed MATS rule compliance plan for emissions controls necessary for the continued operation of Plants Bowen Units 1 through 4, Wansley Units 1 and 2, Scherer Units 1 through 3, and Hammond Units 1 through 4, the switch to natural gas as the primary fuel at Plant Yates Units 6 and 7 and SEGCO's Plant Gaston Units 1 through 4, as well as the fuel switch at Plant McIntosh Unit 1 to operate on Powder River Basin coal. See Note 1 under "Affiliate Transactions" herein for additional information regarding the fuel switch at SEGCO's generating units.
In the 2013 ARP, the Georgia PSC approved the amortization of the construction work in progress (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 beginning in January 2014 and the amortization of any 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. The Georgia PSC deferred a decision regarding the appropriate recovery period for the costs associated with unusable materials and supplies remaining at the retiring plants to the Company's next base rate case, which the Company expects to file in 2016 (2016 Rate Case). In the 2013 IRP, the Georgia PSC also deferred decisions regarding the recovery of any fuel related costs that could be incurred in connection with the retirement units to be addressed in future fuel cases.
A request was filed with the Georgia PSC on January 10, 2014 to cancel the proposed biomass fuel conversion of Plant Mitchell Unit 3 (155 MWs) because it would not be cost effective for customers. The filing also notified the Georgia PSC of the Company’s plans to seek decertification later this year. Plant Mitchell Unit 3 will continue to operate as a coal unit until April 2015 when it will be required to cease operation or install additional environmental controls to comply with the MATS rule. In connection with the retirement decision, the Company reclassified the retail portion of the net carrying value of Plant Mitchell Unit 3 from plant in service, net of depreciation, to other utility plant, net.

The decertification of these units and fuel conversions are not expected to have a material impact on the Company's financial statements; however, the ultimate outcome depends on the Georgia PSC's order in the 2016 Rate Case and future fuel cases and cannot be determined at this time.

Renewables Development

On December 17, 2013, four PPAs totaling 50 MWs of utility scale solar generation under the Georgia Power Advanced Solar Initiative (GPASI) were approved by the Georgia PSC, with the Company as the purchaser. These contracts will begin in 2015 and end in 2034. The resulting purchases will be for energy only and recovered through the Company’s fuel cost recovery mechanism. Under the 2013 IRP, the Georgia PSC approved an additional 525 MWs of solar generation to be purchased by the Company. The 525 MWs will be divided into 425 MWs of utility scale projects and 100 MWs of distributed generation.

NOTES (continued)
Georgia Power Company 2013 Annual Report

On November 4, 2013, the Company filed an application for the certification of two PPAs which were executed on April 22, 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.

During 2013, the Company executed four PPAs to purchase a total of 169 MWs of biomass capacity and energy from four facilities in Georgia that will begin in 2015 and end in 2035. On May 21, 2013, the Georgia PSC approved two of the biomass PPAs and the remaining two were approved on December 17, 2013. The four biomass PPAs are contingent upon the counterparty meeting specified contract dates for posting collateral and commercial operation. The ultimate outcome of this matter cannot be determined at this time.

Fuel Cost Recovery

The Company has established fuel cost recovery rates approved by the Georgia PSC. The Georgia PSC approved reductions in the Company's total annual billings of approximately $43 million effective June 1, 2011, $567 million effective June 1, 2012, and $122 million effective January 1, 2013. The 2013 reduction was due to the Georgia PSC authorizing an Interim Fuel Rider, which is set to expire June 1, 2014. The Company 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. The Company's fuel cost recovery includes costs associated with a natural gas hedging program as revised and approved by the Georgia PSC on February 7, 2013, requiring it to use options and hedges within a 24-month time horizon. See Note 11 under "Energy-Related Derivatives" for additional information. On February 18, 2014, the Georgia PSC approved the deferral of the Company's next fuel case, which is now expected to be filed by March 1, 2015.

The Company's over recovered fuel balance totaled approximately $58 million and $230 million at December 31, 2013 and 2012, respectively, and is included in current liabilities and other deferred credits and liabilities.

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

Nuclear Construction

In 2008, the Company, acting for itself and as agent for Oglethorpe Power Corporation (OPC), the Municipal Electric Authority of Georgia (MEAG Power), and the City of Dalton, Georgia (Dalton), acting by and through its Board of Water, Light, and Sinking Fund Commissioners (collectively, Owners), entered into an agreement with a consortium consisting of Westinghouse Electric Company LLC (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 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. Each Owner is severally (and not jointly) liable for its proportionate share, based on its ownership interest, of all amounts owed to the Contractor under the Vogtle 3 and 4 Agreement. The Company's proportionate share is 45.7%. The Vogtle 3 and 4 Agreement provides for liquidated damages upon the Contractor's failure to fulfill the schedule and performance guarantees. The Contractor's liability to the Owners for schedule and performance liquidated damages and warranty claims is subject to a cap.

Certain payment obligations of Westinghouse and Stone & Webster, Inc. under the Vogtle 3 and 4 Agreement are guaranteed by Toshiba Corporation and The Shaw Group, Inc., respectively. In the event of certain credit rating downgrades of any Owner, such Owner will be required to provide a letter of credit or other credit enhancement. The Owners may terminate the Vogtle 3 and 4 Agreement at any time for their convenience, provided that the Owners will be required to pay certain termination costs. The Contractor may terminate the Vogtle 3 and 4 Agreement under certain circumstances, including certain 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 Owners, 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, effective December 30, 2011, and issued combined construction and operating licenses (COLs) in February 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 are expected as construction proceeds.

NOTES (continued)
Georgia Power Company 2013 Annual Report

In 2009, the Georgia PSC approved inclusion of the Plant Vogtle Units 3 and 4 related CWIP accounts in rate base, and the State of Georgia enacted the Georgia Nuclear Energy Financing Act, which allows the Company to recover financing costs for nuclear construction projects certified by the Georgia PSC. Financing costs are recovered on all applicable certified costs through annual adjustments to the Nuclear Construction Cost Recovery (NCCR) tariff by including the related CWIP accounts in rate base during the construction period. The Georgia PSC approved increases to the NCCR tariff of approximately $223 million, $35 million, $50 million, and $60 million, effective January 1, 2011, 2012, 2013, and 2014, respectively. Through the NCCR tariff, the Company is collecting and amortizing to earnings approximately $91 million of financing costs, capitalized in 2009 and 2010, over the five-year period ending December 31, 2015, in addition to the ongoing financing costs. At December 31, 2013, approximately $37 million of these 2009 and 2010 costs remained unamortized in CWIP.

The Company is required to file semi-annual Vogtle Construction Monitoring (VCM) reports with the Georgia PSC by February 28 and August 31 each year. If the projected certified construction capital costs to be borne by the Company increase by 5% or the projected in-service dates are significantly extended, the Company is required to seek an amendment to the Plant Vogtle Units 3 and 4 certificate from the Georgia PSC. Accordingly, the Company's eighth VCM report 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 and the fourth quarter 2018 for Plant Vogtle Units 3 and 4, respectively.

On September 3, 2013, the Georgia PSC approved a stipulation entered into by the Company and the Georgia PSC staff to waive the requirement to amend the Plant Vogtle Units 3 and 4 certificate, until the commercial operation date of Plant Vogtle Unit 3, or earlier if deemed appropriate by the Georgia PSC and the Company. In accordance with the Georgia Integrated Resource Planning Act, any costs incurred by the Company in excess of the certified amount will not be included in rate base, unless shown to be reasonable and prudent. In addition, financing costs on any excess construction-related costs potentially would be subject to recovery through AFUDC instead of the NCCR tariff. As required by the stipulation, the Company filed an abbreviated status update with the Georgia PSC on September 3, 2013, which reflected approximately $2.4 billion of total construction capital costs incurred through June 30, 2013. On October 15, 2013, the Georgia PSC voted to approve the Company's eighth VCM report, reflecting construction capital costs incurred, which through December 31, 2012 totaled approximately $2.2 billion. Also in accordance with the stipulation, the Company will file with the Georgia PSC on February 28, 2014 a combined ninth and tenth VCM report covering the period from January 1 through December 31, 2013 (Ninth/Tenth VCM report), which will request approval for an additional $0.4 billion of construction capital costs. The Ninth/Tenth VCM report will reflect estimated in-service construction capital costs of $4.8 billion and associated financing costs during the construction period, which are estimated to total approximately $2.0 billion. The Company expects to resume filing semi-annual VCM reports in August 2014.

In July 2012, the Owners and the Contractor began negotiations 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 Owners are responsible for these costs under the terms of the Vogtle 3 and 4 Agreement. The portion of the additional costs claimed by the Contractor that would be attributable to the Company (based on the Company's ownership interest) with respect to these issues is approximately $425 million (in 2008 dollars). The Contractor also has asserted it is entitled to further schedule extensions. The Company has not agreed with either the proposed cost or schedule adjustments or that the Owners have any responsibility for costs related to these issues. In November 2012, the Company and the other Owners filed suit against the Contractor in the U.S. District Court for the Southern District of Georgia seeking a declaratory judgment that the Owners are not responsible for these costs. Also in November 2012, the Contractor filed suit against the Company and the other Owners in the U.S. District Court for the District of Columbia alleging the Owners are responsible for these costs. On August 30, 2013, the U.S. District Court for the District of Columbia dismissed the Contractor's suit, ruling that the proper venue is the U.S. District Court for the Southern District of Georgia. The Contractor appealed the decision to the U.S. Court of Appeals for the

District of Columbia Circuit on September 27, 2013. While litigation has commenced and the Company intends to vigorously defend its positions, the Company also expects negotiations with the Contractor to continue with respect to cost and schedule during which negotiations the parties may reach a mutually acceptable compromise of their positions.

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 are expected to 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 Owners, the Contractor, or both.

As construction continues, the risk remains that additional challenges in the fabrication, assembly, delivery, and installation of structural modules, delays in the receipt of the remaining permits necessary for the operation of Plant Vogtle Units 3 and 4, or

NOTES (continued)
Georgia Power Company 2013 Annual Report

other issues could arise and may further impact project schedule and cost. Additional claims by the Contractor or the Company (on behalf of the Owners) are also likely to arise throughout construction. These claims may be resolved through formal and informal dispute resolution procedures under the Vogtle 3 and 4 Agreement, but also may be resolved through litigation.

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

4. JOINT OWNERSHIP AGREEMENTS

The Company and Alabama Power own equally all of the outstanding capital stock of SEGCO, which owns electric generating units with a total rated capacity of 1,020 MWs, as well as associated transmission facilities. The capacity of these units is sold equally to the Company and Alabama Power under a power contract. The Company and Alabama Power make payments sufficient to provide for the operating expenses, taxes, interest expense, and a return on equity. The Company's share of purchased power totaled $91 million in 2013, $107 million in 2012, and $141 million in 2011 and is included in purchased power, affiliates in the statements of income. The Company accounts for SEGCO using the equity method.

The Company owns undivided interests in Plants Vogtle, Hatch, Wansley, and Scherer in varying amounts jointly with one or more of the following entities: OPC, MEAG Power, Dalton, Florida Power & Light Company, Jacksonville Electric Authority, and Gulf Power. Under these agreements, the Company has been contracted to operate and maintain the plants as agent for the co-owners and is jointly and severally liable for third party claims related to these plants. In addition, the Company jointly owns the Rocky Mountain pumped storage hydroelectric plant with OPC who is the operator of the plant. The Company and Duke Energy Florida, Inc. jointly own a combustion turbine unit (Intercession City) operated by Duke Energy Florida, Inc.

At December 31, 2013, the Company's percentage ownership and investment (exclusive of nuclear fuel) in jointly-owned facilities in commercial operation with the above entities were as follows:

Facility (Type)	Company Ownership	Plant in Service	Accumulated Depreciation	CWIP
	(in millions)			
Plant Vogtle (nuclear)				
Units 1 and 2	45.7%	$3,375	$2,028	$53
Plant Hatch (nuclear)	50.1	1,092	551	52
Plant Wansley (coal)	53.5	800	260	36
Plant Scherer (coal)				
Units 1 and 2	8.4	209	80	24
Unit 3	75.0	1,155	398	19
Rocky Mountain (pumped storage)	25.4	182	120	—
Intercession City (combustion-turbine)	33.3	14	4	—

The Company's proportionate share of its plant operating expenses is included in the corresponding operating expenses in the statements of income and the Company is responsible for providing its own financing.

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

5. INCOME TAXES

On behalf of the Company, Southern Company files a consolidated federal income tax return and combined state income tax returns for the States of Alabama, Georgia, and Mississippi. 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.

Table of Contents Index to Financial Statements

NOTES (continued)
Georgia Power Company 2013 Annual Report

Current and Deferred Income Taxes
Details of income tax provisions are as follows:

	2013	2012	2011
	(in millions)		
Federal –			
Current	$277	$273	$106
Deferred	374	370	479
	651	643	585
State –			
Current	(30)	38	19
Deferred	102	7	21
	72	45	40
Total	$723	$688	$625

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:

	2013	2012
	(in millions)	
Deferred tax liabilities –		
Accelerated depreciation	$4,479	$4,201
Property basis differences	873	757
Employee benefit obligations	232	255
Premium on reacquired debt	73	77
Regulatory assets associated with employee benefit obligations	276	536
Asset retirement obligations	495	446
Other	168	93
Total	6,596	6,365
Deferred tax assets –		
Federal effect of state deferred taxes	159	142
Employee benefit obligations	388	644
Other property basis differences	93	100
Other deferred costs	84	39
Cost of removal obligations	17	29
State tax credit carry forward	118	86
Federal tax credit carry forward	3	—
Over-recovered fuel costs	22	89
Unbilled fuel revenue	53	39
Asset retirement obligations	495	446
Other	32	42
Total	1,464	1,656
Total deferred tax liabilities, net	5,132	4,709
Portion included in current assets/(liabilities), net	68	152
Accumulated deferred income taxes	$5,200	$4,861

At December 31, 2013, tax-related regulatory assets were $722 million. These assets are primarily attributable to tax benefits flowed through to customers in prior years, deferred taxes previously recognized at rates lower than the current enacted tax law, and taxes applicable to capitalized interest.

At December 31, 2013, tax-related regulatory liabilities to be credited to customers were $112 million. These liabilities are primarily attributable to deferred taxes previously recognized at rates higher than current enacted tax law and to unamortized ITCs. In 2011, the Company recorded a regulatory liability of $62 million related to a settlement with the Georgia Department of Revenue resolving claims for certain tax credits in 2005 through 2009. Amortization of the regulatory liability occurred ratably over the period from April 2012 through December 2013.

In accordance with regulatory requirements, deferred federal ITCs are amortized over the life of the related property with such amortization normally applied as a credit to reduce depreciation in the statements of income. Credits amortized in this manner amounted to $5 million in 2013, $13 million in 2012, and $9 million in 2011. State ITCs are recognized in the period in which the credits are claimed on the state income tax return and totaled $27 million in 2013, $36 million in 2012, and $53 million in 2011. At December 31, 2013, the Company had $3 million in federal tax credit carry forwards that will expire by 2032 and $118 million in state ITC carry forwards that will expire between 2020 and 2024.

In 2010, the Tax Relief, Unemployment Insurance Reauthorization, and Job Creation Act of 2010 (Tax Relief Act) was signed into law. Major tax incentives in the Tax Relief Act include 100% bonus depreciation for property placed in service after September 8, 2010 and through 2011 (and for certain long-term production-period projects placed in service in 2012) and 50% bonus depreciation for property placed in service in 2012 (and for certain long-term production-period projects placed in service in 2013).

On January 2, 2013, the American Taxpayer Relief Act of 2012 (ATRA) was signed into law. The ATRA retroactively extended several tax credits through 2013 and extended 50% bonus depreciation for property placed in service in 2013 (and for certain long-term production-period projects to be placed in service in 2014).

The application of the bonus depreciation provisions in these laws significantly increased deferred tax liabilities related to accelerated depreciation in 2013, 2012, and 2011.

Effective Tax Rate

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

	2013		2012		2011	
Federal statutory rate	35.0	%	35.0	%	35.0	%
State income tax, net of federal deduction	2.5		1.6		1.5	
Non-deductible book depreciation	1.3		1.2		0.8	
AFUDC equity	(0.6	)	(1.0	)	(1.9	)
Other	(0.4	)	(0.1	)	(0.5	)
Effective income tax rate	37.8	%	36.7	%	34.9	%

The increase in the Company's 2013 effective tax rate is primarily the result of a decrease in state income tax credits and non-taxable AFUDC equity. The increase in the Company's 2012 effective tax rate is primarily the result of an increase in non-deductible book depreciation and a decrease in non-taxable AFUDC equity.

NOTES (continued)
Georgia Power Company 2013 Annual Report

Unrecognized Tax Benefits

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

	2013	2012	2011
	(in millions)		
Unrecognized tax benefits at beginning of year	$23	$47	$237
Tax positions from current periods	—	3	9
Tax positions increase from prior periods	—	3	—
Tax positions decrease from prior periods	(23)	(19)	(87)
Reductions due to settlements	—	(8)	(112)
Reductions due to expired statute of limitations	—	(3)	—
Balance at end of year	$—	$23	$47

The tax positions decrease from prior periods for 2013 relates primarily to the tax accounting method change for repairs-generation assets. See "Tax Method of Accounting for Repairs" herein for additional information.

In addition, the tax reductions due to expired statute of limitations for 2012 relate to the Georgia jobs and retraining tax credits and the Georgia manufacturer's ITCs.

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

	2013	2012	2011
	(in millions)		
Tax positions impacting the effective tax rate	$—	$—	$28
Tax positions not impacting the effective tax rate	—	23	19
Balance of unrecognized tax benefits	$—	$23	$47

The tax positions not impacting the effective tax rate for 2012 relate to the timing difference associated with the tax accounting method change for repairs-generation assets. See "Tax Method of Accounting for Repairs" herein for additional 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 as follows:

	2013	2012	2011
	(in millions)		
Interest accrued at beginning of year	$—	$6	$27
Interest reclassified due to settlements	—	(6)	(24)
Interest accrued during the year	—	—	3
Balance at end of year	$—	$—	$6

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

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

The IRS has finalized its audits of Southern Company's consolidated federal income tax returns through 2011. Southern Company has filed its 2012 federal income tax return and has received a full acceptance letter from the IRS; however, the IRS has not finalized its audit. For tax years 2012 and 2013, Southern Company was a participant in the Compliance Assurance Process of the IRS. The audits for the Company's state income tax returns have either been concluded, or the statute of limitations has expired, for years prior to 2007.

Tax Method of Accounting for Repairs

In 2011, the IRS published regulations on the deduction and capitalization of expenditures related to tangible property that generally apply for tax years beginning on or after January 1, 2014. Additionally, on April 30, 2013, the IRS issued Revenue

NOTES (continued)
Georgia Power Company 2013 Annual Report

Procedure 2013-24, which provides guidance for taxpayers related to the deductibility of repair costs associated with generation assets. Based on a review of the regulations, Southern Company incorporated provisions related to repair costs for generation assets into its consolidated 2012 federal income tax return and reversed all related unrecognized tax positions. On September 19, 2013, the IRS issued Treasury Decision 9636, "Guidance Regarding Deduction and Capitalization of Expenditures Related to Tangible Property," which are final tangible property regulations applicable to taxable years beginning on or after January 1, 2014. Southern Company is currently reviewing this new guidance. The ultimate outcome of this matter cannot be determined at this time; however, these regulations are not expected to have a material impact on the Company's financial statements.

6. FINANCING

Securities Due Within One Year

A summary of scheduled maturities of long-term debt due within one year at December 31 was as follows:

	2013	2012
	(in millions)	
Senior notes	$—	$1,675
Capital lease	5	5
Total	$5	$1,680

Maturities through 2018 applicable to total long-term debt are as follows: $5 million in 2014; $1.1 billion in 2015; $710 million in 2016; $457 million in 2017; and $277 million in 2018.

Senior Notes

The Company issued $850 million aggregate principal amount of unsecured senior notes in 2013. The proceeds of these issuances were used to fund a portion of the Company's repayment of $1.8 billion of unsecured senior notes and $300 million of an unsecured bank term loan, to repay a portion of the Company's short-term indebtedness, and for general corporate purposes, including the Company's continuous construction program.

At December 31, 2013 and 2012, the Company had $6.9 billion and $7.9 billion of senior notes outstanding, respectively. These senior notes are effectively subordinated to all secured debt of the Company, which aggregated $45 million and $50 million at December 31, 2013 and 2012, respectively. As of December 31, 2013 and 2012, the Company's secured debt was related to capital lease obligations.

See "DOE Loan Guarantee Borrowings" for information regarding additional secured borrowings incurred by the Company subsequent to December 31, 2013.

Pollution Control Revenue Bonds

Pollution control obligations represent loans to the Company from public authorities of funds derived from sales by such authorities of revenue bonds issued to finance pollution control and solid waste disposal facilities. The Company is required to make payments sufficient for the authorities to meet principal and interest requirements of such bonds. The amount of tax-exempt pollution control revenue bonds outstanding at December 31, 2013 and 2012 was $1.7 billion and $1.8 billion, respectively. Proceeds from certain issuances are restricted until qualifying expenditures are incurred.

In 2013, the Company incurred obligations in connection with issuance by public authorities of an aggregate of $194 million of pollution control revenue bonds. The proceeds of these issuances were used to redeem $194 million of outstanding pollution control bonds. Also in November 2013, the Company purchased and now holds $104.6 million aggregate principal amount of pollution control revenue bonds issued for its benefit in 2013.

Bank Term Loans

In March 2013, the Company entered into three 60-day floating rate bank loans bearing interest based on one-month London Interbank Offered Rate (LIBOR). Each of these short-term loans was for $100 million aggregate principal amount, and the proceeds were used for working capital and other general corporate purposes, including the Company's continuous construction program. These bank loans were repaid at maturity.

In November 2013, the Company entered into three four-month floating rate bank loans for an aggregate principal amount of $400 million, bearing interest based on one-month LIBOR. The proceeds of these short-term loans were used for working capital and other general corporate purposes, including the Company's continuous construction program. At December 31, 2013, these

NOTES (continued)
Georgia Power Company 2013 Annual Report

bank term loans are included in notes payable on the balance sheets. Subsequent to December 31, 2013, the Company repaid these bank term loans. There were no bank term loans outstanding at December 31, 2012.

These bank loans have covenants that limit debt levels to 65% of total capitalization, as defined in the agreements. For purposes of these definitions, debt excludes long-term debt payable to affiliated trusts and other hybrid securities. At December 31, 2013, the 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), the Company and the DOE entered into a loan guarantee agreement (Loan Guarantee Agreement) on February 20, 2014, under which the DOE agreed to guarantee the obligations of the Company under a note purchase agreement (FFB Note Purchase Agreement) among the DOE, the Company, and the Federal Financing Bank (FFB) and a related promissory note (FFB Promissory Note). The FFB Note Purchase Agreement and the FFB Promissory Note provide for a multi-advance term loan facility (FFB Credit Facility), under which the Company may make term loan borrowings through the FFB.

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

All borrowings under the FFB Credit Facility are full recourse to the Company, and the Company is obligated to reimburse the DOE in the event the DOE is required to make any payments to FFB under the DOE guarantee. The Company's reimbursement obligations to the DOE are secured by a first priority lien on (i) the Company's 45.7% undivided ownership interest in Plant Vogtle Units 3 and 4 and (ii) the Company's rights and obligations under the principal contracts relating to Plant Vogtle Units 3 and 4. There are no restrictions on the Company's ability to grant liens on other property.

Advances may be requested under the FFB Credit Facility on a quarterly basis through December 31, 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%.

On February 20, 2014, the Company 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 February 20, 2044 (the final maturity date) and the interest rate applicable to the remaining $500 million is 3.488% for an interest period that extends to February 20, 2029, and will be reset from time to time thereafter through the final maturity date. In connection with its entry into the Loan Guarantee Agreement, the FFB Note Purchase Agreement, and the FFB Promissory Note, the Company incurred issuance costs of approximately $67 million, which will be amortized over the life of the borrowings under the FFB Credit Facility.

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, compliance with the Cargo Preference Act of 1954, and certification from the DOE's consulting engineer that proceeds of the advances are used to reimburse Eligible Project Costs.

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

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

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

NOTES (continued)
Georgia Power Company 2013 Annual Report

Capital Leases

Assets acquired under capital leases are recorded in the balance sheets as utility plant in service, and the related obligations are classified as long-term debt. At December 31, 2013 and 2012, the Company had a capital lease asset for its corporate headquarters building of $61 million, with accumulated depreciation at December 31, 2013 and 2012 of $16 million and $11 million, respectively. At December 31, 2013 and 2012, the capitalized lease obligation was $45 million and $50 million, respectively, with an interest rate of 7.9% for both years. For ratemaking purposes, the Georgia PSC has allowed only the lease payments in cost of service. The difference between the accrued expense and the lease payments allowed for ratemaking purposes has been deferred and is being amortized to expense as ordered by the Georgia PSC. The annual expense incurred for all capital leases was not material for any year presented. See Note 7 under "Fuel and Purchased Power Agreements" for additional information on capital lease PPAs that become effective in 2015.

Outstanding Classes of Capital Stock

The Company currently has preferred stock, Class A preferred stock, preference stock, and common stock authorized. The Company has shares of its Class A preferred stock, preference stock, and common stock outstanding. The Company's Class A preferred stock ranks senior to the Company's preference stock and common stock with respect to payment of dividends and voluntary or involuntary dissolution. The Company's preference stock ranks senior to the common stock with respect to the payment of dividends and voluntary or involuntary dissolution. The outstanding series of the Class A preferred stock is subject to redemption at the option of the Company at any time at a redemption price equal to 100% of the par value. In addition, on or after October 1, 2017, the Company may redeem the outstanding series of the preference stock at a redemption price equal to 100% of the par value. With respect to any redemption of the preference stock prior to October 1, 2017, the redemption price includes a make-whole premium based on the present value of the liquidation amount and future dividends through the first par redemption date.

Dividend Restrictions

The Company can only pay dividends to Southern Company out of retained earnings or paid-in-capital.

Bank Credit Arrangements

At December 31, 2013, committed credit arrangements with banks were as follows:

Expires[(a)]			
2016	2018	Total	Unused
(in millions)			
$150	$1,600	$1,750	$1,736

(a) No credit arrangements expire in 2014, 2015, or 2017.

The Company expects to renew its credit arrangements, as needed, prior to expiration. All the credit arrangements require payment of commitment fees based on the unused portion of the commitments. Commitment fees average less than $^1/4$ of 1% for the Company.

The credit arrangements have covenants that limit the Company's debt levels to 65% of total capitalization, as defined in the agreements. For purposes of these definitions, debt excludes certain hybrid securities.

A portion of the $1.7 billion of unused credit arrangements with banks is allocated to provide liquidity support to the Company's variable rate pollution control revenue bonds and its commercial paper borrowings. The amount of variable rate pollution control revenue bonds outstanding requiring liquidity support as of December 31, 2013 was $862 million. In addition, at December 31, 2013, the Company had $242 million of fixed rate pollution control revenue bonds that will be required to be remarketed within the next 12 months.

The Company makes short-term borrowings primarily through a commercial paper program that has the liquidity support of the Company's committed bank credit arrangements. The Company may also borrow through various other arrangements with banks. Commercial paper and short-term bank term loans are included in notes payable on the balance sheets.

NOTES (continued)
Georgia Power Company 2013 Annual Report

The Company had $1.0 billion of short-term debt outstanding at December 31, 2013. The Company had no short-term debt outstanding at December 31, 2012, excluding $2 million of notes payable related to other energy service contracts. Details of short-term borrowings outstanding at December 31, 2013 were as follows:

	Short-term Debt at the End of the Period		
	Amount Outstanding	Weighted Average Interest Rate	
	(in millions)		
December 31, 2013:			
Commercial paper	$647	0.2	%
Short-term bank debt	400	0.9	%
Total	$1,047	0.5	%

7. COMMITMENTS

Fuel and Purchased Power Agreements

To supply a portion of the fuel requirements of its generating plants, the Company has entered into various long-term commitments for the procurement and delivery of fossil and nuclear fuel which are not recognized on the balance sheets. In 2013, 2012, and 2011, the Company incurred fuel expense of $2.3 billion, $2.1 billion, and $2.8 billion, respectively, the majority of which was purchased under long-term commitments. The Company expects that a substantial amount of its future fuel needs will continue to be purchased under long-term commitments.

The Company has commitments regarding a portion of a 5% interest in the original cost of Plant Vogtle Units 1 and 2 owned by MEAG Power that are in effect until the latter of the retirement of the plant or the latest stated maturity date of MEAG Power's bonds issued to finance such ownership interest. The payments for capacity are required whether or not any capacity is available. The energy cost is a function of each unit's variable operating costs. Portions of the capacity payments relate to costs in excess of MEAG Power's Plant Vogtle Unit 1 and 2 allowed investment for ratemaking purposes. The present value of these portions at the time of the disallowance was written off. Generally, the cost of such capacity and energy is included in purchased power, non-affiliates in the statements of income. Capacity payments totaled $27 million, $50 million, and $52 million in 2013, 2012, and 2011, respectively.

NOTES (continued)
Georgia Power Company 2013 Annual Report

The Company has also entered into various long-term PPAs, some of which are accounted for as capital or operating leases. Total capacity expense under PPAs accounted for as operating leases was $162 million, $169 million, and $216 million for 2013, 2012, and 2011, respectively. Estimated total long-term obligations at December 31, 2013 were as follows:

	Affiliate Capital Leases (in millions)	Non-Affiliate Capital Leases [4]	Affiliate Operating Leases	Non-Affiliate Operating Leases [4]	Vogtle Units 1 and 2 Capacity Payments	Total ($)
2014	$—	$—	$55	$112	$21	$188
2015	22	20	89	127	13	271
2016	22	26	99	142	11	300
2017	23	27	71	144	8	273
2018	23	27	62	145	7	264
2019 and thereafter	278	541	669	1,573	58	3,119
Total	$368	$641	$1,045	$2,243	$118	$4,415
Less: amounts representing executory costs[1]	55	142				
Net minimum lease payments	313	499				
Less: amounts representing interest[2]	85	166				
Present value of net minimum lease payments[3]	$228	$333				

(1) Executory costs such as taxes, maintenance, and insurance (including the estimated profit thereon) are estimated and included in total minimum lease payments.
(2) Calculated at the Company's incremental borrowing rate at the inception of the leases.
(3) When the PPAs begin in 2015, the Company will recognize capital lease assets and capital lease obligations totaling $482 million, equal to the lesser of the present value of the net minimum lease payments or the estimated fair value of the leased property.
(4) A total of $1.3 billion of biomass PPAs included under the non-affiliate capital and operating leases is contingent upon the counterparty meeting specified contract dates for posting collateral and commercial operation.

SCS may enter into various types of wholesale energy and natural gas contracts acting as an agent for the Company and all of the other Southern Company traditional operating companies and Southern Power. Under these agreements, each of the traditional operating companies and Southern Power may be jointly and severally liable. Accordingly, Southern Company has entered into keep-well agreements with the Company and each of the other traditional operating companies to ensure the Company will not subsidize or be responsible for any costs, losses, liabilities, or damages resulting from the inclusion of Southern Power as a contracting party under these agreements.

Operating Leases

In addition to the PPA operating leases discussed above, the Company has other operating lease agreements with various terms and expiration dates. Total rent expense was $32 million for 2013, $34 million for 2012, and $33 million for 2011. The Company includes any step rents, fixed escalations, and lease concessions in its computation of minimum lease payments.

NOTES (continued)
Georgia Power Company 2013 Annual Report

As of December 31, 2013, estimated minimum lease payments under operating leases were as follows:

	Minimum Lease Payments		
	Railcars	Other	Total
	(in millions)		
2014	$20	$6	$26
2015	14	6	20
2016	8	5	13
2017	5	4	9
2018	2	4	6
2019 and thereafter	—	11	11
Total	$49	$36	$85

Railcar minimum lease payments are disclosed at 100% of railcar lease obligations; however, a portion of these obligations is shared with the joint owners of Plants Scherer and Wansley. A majority of the rental expenses related to the railcar leases are recoverable through the fuel cost recovery clause as ordered by the Georgia PSC and the remaining portion is recovered through base rates.

In addition to the above rental commitments, the Company has obligations upon expiration of certain railcar leases with respect to the residual value of the leased property. These leases have terms expiring through 2018 with maximum obligations under these leases of $30 million. At the termination of the leases, the lessee may either exercise its purchase option or the property can be sold to a third party. The Company expects that the fair market value of the leased property would substantially reduce or eliminate the Company's payments under the residual value obligations.

Guarantees

Alabama Power has guaranteed the obligations of SEGCO for $25 million of pollution control revenue bonds issued in 2001, which mature in June 2019 and also $100 million of senior notes issued in November 2013, which mature in December 2018. The Company has agreed to reimburse Alabama Power for the pro rata portion of such obligations corresponding to the Company's then proportionate ownership of SEGCO's stock if Alabama Power is called upon to make such payment under its guarantee. See Note 4 for additional information.

In addition, subsequent to December 31, 2013, the Company entered into an agreement that requires the Company to guarantee certain payments of a gas supplier for Plant McIntosh for a period up to 15 years. The guarantee is expected to be terminated if certain events occur within one year of the initial gas deliveries in 2017. In the event the gas supplier defaults on payments, the maximum potential exposure under the guarantee is approximately $43 million.

As discussed earlier in this Note under "Operating Leases," the Company has entered into certain residual value guarantees related to railcar leases.

8. STOCK COMPENSATION

Stock Options

Southern Company provides non-qualified stock options through its Omnibus Incentive Compensation Plan to a large segment of the Company's employees ranging from line management to executives. As of December 31, 2013, there were 1,265 current and former employees of the Company participating in the stock option program, and there were 28 million shares of Southern Company common stock remaining available for awards under the Omnibus Incentive Compensation Plan. The prices of options were at the fair market value of the shares on the dates of grant. These options become exercisable pro rata over a maximum period of three years from the date of grant. The Company generally recognizes stock option expense on a straight-line basis over the vesting period which equates to the requisite service period; however, for employees who are eligible for retirement, the total cost is expensed at the grant date. Options outstanding will expire no later than 10 years after the date of grant, unless terminated earlier by the Southern Company Board of Directors in accordance with the Omnibus Incentive Compensation Plan. Stock options held by employees of a company undergoing a change in control vest upon the change in control.

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	2013	2012	2011
Expected volatility	16.6%	17.7%	17.5%
Expected term (in years)	5.0	5.0	5.0
Interest rate	0.9%	0.9%	2.3%
Dividend yield	4.4%	4.2%	4.8%
Weighted average grant-date fair value	$2.93	$3.39	$3.23

The Company's activity in the stock option program for 2013 is summarized below:

	Shares Subject to Option	Weighted Average Exercise Price
Outstanding at December 31, 2012	6,547,498	$36.18
Granted	1,509,662	44.09
Exercised	(1,196,585)	33.38
Cancelled	(11,421)	40.99
Outstanding at December 31, 2013	6,849,154	$38.41
Exercisable at December 31, 2013	4,321,853	$35.51

The number of stock options vested, and expected to vest in the future, as of December 31, 2013 was not significantly different from the number of stock options outstanding at December 31, 2013 as stated above. As of December 31, 2013, the weighted average remaining contractual term for the options outstanding and options exercisable was approximately six years and five years, respectively, and the aggregate intrinsic value for the options outstanding and options exercisable was $27 million and $26 million, respectively.
As of December 31, 2013, the amount of unrecognized compensation cost related to stock option awards not yet vested was immaterial.
The compensation cost and tax benefits related to the grant and exercise of Southern Company stock options to the Company's employees are recognized in the Company's financial statements with a corresponding credit to equity, representing a capital contribution from Southern Company. The amounts were not material for any year presented.
The total intrinsic value of options exercised during the years ended December 31, 2013, 2012, and 2011 was $16 million, $34 million, and $32 million, respectively. The actual tax benefit realized by the Company for the tax deductions from stock option exercises totaled $6 million, $13 million, and $12 million for the years ended December 31, 2013, 2012, and 2011, respectively.
Performance Shares
Southern Company provides performance share award units through its Omnibus Incentive Compensation Plan to a large segment of the Company's employees ranging from line management to executives. The performance share units granted under the plan vest at the end of a three-year performance period which equates to the requisite service period. Employees that retire prior to the end of the three-year period receive a pro rata number of shares, issued at the end of the performance period, based on actual months of service prior to retirement. The value of the award units is based on Southern Company's total shareholder return (TSR) over the three-year performance period which measures Southern Company's relative performance against a group of industry peers. The performance shares are delivered in common stock following the end of the performance period based on Southern Company's actual TSR and may range from 0% to 200% of the original target performance share amount.
The fair value of performance share awards is determined as of the grant date using a Monte Carlo simulation model to estimate the TSR of Southern Company's stock among the industry peers over the performance period. The

Company recognizes compensation expense on a straight-line basis over the three-year performance period without remeasurement. Compensation expense for awards where the service condition is met is recognized regardless of the actual number of shares issued. 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 award units.

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	2013	2012	2011
Expected volatility	12.0%	16.0%	19.2%
Expected term (in years)	3.0	3.0	3.0
Interest rate	0.4%	0.4%	1.4%
Annualized dividend rate	$1.96	$1.89	$1.82
Weighted average grant-date fair value	$40.50	$41.99	$35.97

Total unvested performance share units outstanding as of December 31, 2012 were 280,000. During 2013, 161,240 performance share units were granted, 151,769 performance shares were vested, and 16,371 performance share units were forfeited, resulting in 273,100 unvested units outstanding at December 31, 2013. In January 2014, the vested performance share award units were converted into 45,239 shares outstanding at a share price of $41.27 for the three-year performance and vesting period ended December 31, 2013.

For the years ended December 31, 2013, 2012, and 2011, total compensation cost for performance share units recognized in income was $6 million, $6 million, and $4 million, respectively, with the related tax benefit also recognized in income of $2 million, $2 million and $1 million, respectively. As of December 31, 2013, there was $6 million of total unrecognized compensation cost related to performance share award units that will be recognized over a weighted-average period of approximately 11 months.

9. NUCLEAR INSURANCE

Under the Price-Anderson Amendments Act (Act), the Company maintains agreements of indemnity with the NRC that, together with private insurance, cover third-party liability arising from any nuclear incident occurring at Plant Hatch and Plant Vogtle Units 1 and 2. The Act provides funds up to $13.6 billion for public liability claims that could arise from a single nuclear incident. Each nuclear plant is insured against this liability to a maximum of $375 million by American Nuclear Insurers (ANI), with the remaining coverage provided by a mandatory program of deferred premiums that could be assessed, after a nuclear incident, against all owners of commercial nuclear reactors. The Company could be assessed up to $127 million per incident for each licensed reactor it operates but not more than an aggregate of $19 million per incident to be paid in a calendar year for each reactor. Such maximum assessment, excluding any applicable state premium taxes, for the Company, based on its ownership and buyback interests in all licensed reactors, is $252 million, per incident, but not more than an aggregate of $37 million to be paid for each incident in any one year. Both the maximum assessment per reactor and the maximum yearly assessment are adjusted for inflation at least every five years. The next scheduled adjustment is due no later than September 10, 2018. See Note 4 to the financial statements herein for additional information on joint ownership agreements.

The Company is a member of Nuclear Electric Insurance Limited (NEIL), a mutual insurer established to provide property damage insurance in an amount up to $500 million for members' operating nuclear generating facilities. Additionally, the Company has NEIL policies that currently provide decontamination, excess property insurance, and premature decommissioning coverage up to $2.25 billion for nuclear losses in excess of the $500 million primary coverage. These policies have a sublimit of $1.7 billion for non-nuclear losses.

NEIL also covers the additional costs that would be incurred in obtaining replacement power during a prolonged accidental outage at a member's nuclear plant. Members can purchase this coverage, subject to a deductible waiting period of up to 26 weeks, with a maximum per occurrence per unit limit of $490 million. After the deductible period, weekly indemnity payments would be received until either the unit is operational or until the limit is exhausted in approximately three years. The Company purchases limits based on the projected full 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 the Company under the NEIL policies would be $65 million.

Claims resulting from terrorist acts are covered under both the ANI and NEIL policies (subject to normal policy limits). The aggregate, however, that NEIL will pay for all claims resulting from terrorist acts in any 12-month period is $3.2 billion plus such additional amounts NEIL can recover through reinsurance, indemnity, or other sources.

For all on-site property damage insurance policies for commercial nuclear power plants, the NRC requires that the proceeds of such policies shall be dedicated first for the sole purpose of placing the reactor in a safe and stable condition after an accident. Any remaining proceeds are to be applied next toward the costs of decontamination and debris removal operations ordered by the NRC, and any further remaining proceeds are to be paid either to the Company or to its debt trustees as may be appropriate under the policies and applicable trust indentures. In the event of a loss, the amount of insurance available might not be adequate to cover property damage and other expenses incurred. Uninsured losses and other expenses, to the extent not recovered from customers, would be borne by the Company and could have a material effect on the Company's financial condition and results of operations.

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

10. FAIR VALUE MEASUREMENTS

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

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

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

Table of Contents Index to Financial Statements

NOTES (continued)
Georgia Power Company 2013 Annual Report

As of December 31, 2013, assets and liabilities measured at fair value on a recurring basis during the period, together with the level of the fair value hierarchy in which they fall, were as follows:

As of December 31, 2013:	Fair Value Measurements Using Quoted Prices in Active Markets for Identical Assets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)	Total
	(in millions)			
Assets:				
Energy-related derivatives	$—	$5	$—	$5
Nuclear decommissioning trusts:[(a)]				
Domestic equity	197	1	—	198
Foreign equity	—	131	—	131
U.S. Treasury and government agency securities	—	79	—	79
Municipal bonds	—	64	—	64
Corporate bonds	—	140	—	140
Mortgage and asset backed securities	—	114	—	114
Other investments	—	24	—	24
Total	$197	$558	$—	$755
Liabilities:				
Energy-related derivatives	$—	$21	$—	$21

(a) 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.

NOTES (continued)
Georgia Power Company 2013 Annual Report

As of December 31, 2012, assets and liabilities measured at fair value on a recurring basis during the period, together with the level of the fair value hierarchy in which they fall, were as follows:

	Fair Value Measurements Using			
As of December 31, 2012:	Quoted Prices in Active Markets for Identical Assets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)	Total
	(in millions)			
Assets:				
Energy-related derivatives	$—	$11	$—	$11
Nuclear decommissioning trusts:[(a)]				
Domestic equity	162	1	—	163
Foreign equity	—	117	—	117
U.S. Treasury and government agency securities	—	105	—	105
Municipal bonds	—	55	—	55
Corporate bonds	—	133	—	133
Mortgage and asset backed securities	—	115	—	115
Other investments	—	10	—	10
Cash equivalents	15	—	—	15
Total	$177	$547	$—	$724
Liabilities:				
Energy-related derivatives	$—	$45	$—	$45

(a) 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, including, from time to time, basis swaps. These are standard products used within the energy industry and are valued using the market approach. The inputs used are mainly from observable market sources, such as forward natural gas prices, implied volatility, and Overnight Index Swap interest rates. See Note 11 for additional information on how these derivatives are used.

For fair value measurements of investments within the nuclear decommissioning trusts, specifically the fixed income assets using significant other observable inputs and unobservable inputs, the primary valuation technique used is the market approach. External pricing vendors are designated for each of the asset classes in the nuclear decommissioning trusts with each security discriminately assigned a primary pricing source, based on similar characteristics.

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, 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' judgment are also obtained when available.

NOTES (continued)
Georgia Power Company 2013 Annual Report

As of December 31, 2013 and 2012, the fair value measurements of investments calculated at net asset value per share (or its equivalent), as well as the nature and risks of those investments, were as follows:

	Fair Value	Unfunded Commitments	Redemption Frequency	Redemption Notice Period
As of December 31, 2013:	(in millions)			
Nuclear decommissioning trusts:				
Foreign equity fund	$131	None	Daily	5 days
Corporate bonds — commingled funds	8	None	Daily	Not applicable
Other — commingled funds	24	None	Daily	Not applicable
As of December 31, 2012:				
Nuclear decommissioning trusts:				
Foreign equity fund	$117	None	Daily	5 days
Corporate bonds — commingled funds	9	None	Daily	Not applicable
Other — commingled funds	10	None	Daily	Not applicable
Cash equivalents:				
Money market funds	15	None	Daily	Not applicable

The NRC requires licensees of commissioned nuclear power reactors to establish a plan for providing reasonable assurance of funds for future decommissioning. The foreign equity fund in the nuclear decommissioning trusts seeks to provide long-term capital appreciation. In pursuing this investment objective, the foreign equity fund primarily invests in a diversified portfolio of equity securities of foreign companies, including those in emerging markets. These equity securities may include, but are not limited to, common stocks, preferred stocks, real estate investment trusts, convertible securities and depositary receipts, including American depositary receipts, European depositary receipts and global depositary receipts, and rights and warrants to buy common stocks. The Company may withdraw all or a portion of its investment on the last business day of each month subject to a minimum withdrawal of $1 million, provided that a minimum investment of $10 million remains. If notices of withdrawal exceed 20% of the aggregate value of the foreign equity fund, then the foreign equity fund's board may refuse to permit the withdrawal of all such investments and may scale down the amounts to be withdrawn pro rata and may further determine that any withdrawal that has been postponed will have priority on the subsequent withdrawal date.

The commingled funds in the nuclear decommissioning trusts are invested primarily in a diversified portfolio including, but not limited to, commercial paper, notes, repurchase agreements, and other evidences of indebtedness with a maturity not exceeding 13 months from the date of purchase. The commingled funds will, however, generally maintain a dollar-weighted average portfolio maturity of 90 days or less. The assets may be longer term investment grade fixed income obligations with maturity shortening provisions. The primary objective for the commingled funds is a high level of current income consistent with stability of principal and liquidity. The commingled funds included within corporate bonds represent the investment of cash collateral received under the Funds' managers' securities lending program that can only be sold upon the return of the loaned securities. See Note 1 under "Nuclear Decommissioning" for additional information.

The money market funds are short-term investments of excess funds in various money market mutual funds, which are portfolios of short-term debt securities. The money market funds are regulated by the SEC and typically receive the highest rating from credit rating agencies. Regulatory and rating agency requirements for money market funds include minimum credit ratings and maximum maturities for individual securities and a maximum weighted average portfolio maturity. Redemptions are available on a same day basis up to the full amount of the Company's investment in the money market funds.

As of December 31, 2013 and 2012, 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:		
2013	$8,593	$8,782
2012	$9,624	$10,427

NOTES (continued)
Georgia Power Company 2013 Annual Report

The fair values are determined using Level 2 measurements and are based on quoted market prices for the same or similar issues or on current rates offered to the Company.

11. DERIVATIVES

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

Energy-Related Derivatives

The Company enters into energy-related derivatives to hedge exposures to electricity, gas, and other fuel price changes. However, due to cost-based rate regulations and other various cost recovery mechanisms, the Company has limited exposure to market volatility in commodity fuel prices and prices of electricity. The Company manages a fuel-hedging program, implemented per the guidelines of the Georgia PSC, through the use of financial derivative contracts, which is expected to continue to mitigate price volatility.

To mitigate residual risks relative to movements in gas prices, the Company may enter into fixed-price contracts for natural gas purchases; however, a significant portion of contracts are priced at market.

Energy-related derivative contracts are accounted for in one of two methods:

- Regulatory Hedges – Energy-related derivative contracts which are designated as regulatory hedges relate primarily to the Company's fuel-hedging program, where gains and losses are initially recorded as regulatory liabilities and assets, respectively, and then are included in fuel expense as the underlying fuel is used in operations and ultimately recovered through the fuel cost recovery mechanism.
- Not Designated – Gains and losses on energy-related derivative contracts that are not designated or fail to qualify as hedges are recognized in the statements of income as incurred.

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

At December 31, 2013, the net volume of energy-related derivative contracts for natural gas positions totaled 60 million mmBtu (million British thermal units), all of which expire by 2017, which is the longest hedge date.

In addition to the volume discussed above, the Company enters into physical natural gas supply contracts that provide the option to sell back excess gas due to operational constraints. The expected volume of natural gas subject to such a feature is 5 million mmBtu for the Company.

Interest Rate Derivatives

The Company may also enter into interest rate derivatives to hedge exposure to changes in interest rates. Derivatives related to existing variable rate securities or forecasted transactions are accounted for as cash flow hedges where the effective portion of the derivatives' fair value gains or losses is recorded in OCI and is reclassified into earnings at the same time the hedged transactions affect earnings. The derivatives employed as hedging instruments are structured to minimize ineffectiveness, which is recorded directly to income.

At December 31, 2013, there were no interest rate derivatives outstanding.

The estimated pre-tax losses that will be reclassified from accumulated OCI to interest expense for the 12-month period ending December 31, 2014 are immaterial. The Company has deferred gains and losses related to interest rate derivative settlements that are expected to be amortized into earnings through 2037.

NOTES (continued)
Georgia Power Company 2013 Annual Report

Derivative Financial Statement Presentation and Amounts
At December 31, 2013 and 2012, the fair value of energy-related derivatives was reflected in the balance sheets as follows:

Derivative Category	Asset Derivatives Balance Sheet Location	2013	2012	Liability Derivatives Balance Sheet Location	2013	2012
		(in millions)			(in millions)	
Derivatives designated as hedging instruments for regulatory purposes						
Energy-related derivatives:	Other current assets	$3	$6	Liabilities from risk management activities	$13	$30
	Other deferred charges and assets	2	5	Other deferred credits and liabilities	8	15
Total derivatives designated as hedging instruments for regulatory purposes		$5	$11		$21	$45

All derivative instruments are measured at fair value. See Note 10 for additional information.
The derivative contracts of the Company 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 contracts 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 at December 31, 2013 and 2012 are presented in the following tables.

Fair Value

Assets	2013	2012	Liabilities	2013	2012
	(in millions)			(in millions)	
Energy-related derivatives presented in the Balance Sheet [(a)]	$5	$11	Energy-related derivatives presented in the Balance Sheet [(a)]	$21	$45
Gross amounts not offset in the Balance Sheet [(b)]	(5)	(11)	Gross amounts not offset in the Balance Sheet [(b)]	(5)	(11)
Net-energy related derivative assets	$—	$—	Net-energy related derivative liabilities	$16	$34

(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, 2013 and 2012, the pre-tax effects of unrealized derivative gains (losses) arising from energy-related derivative instruments designated as regulatory hedging instruments and deferred on the balance sheets were as follows:

Derivative Category	Unrealized Losses Balance Sheet Location	2013	2012	Unrealized Gains Balance Sheet Location	2013	2012
		(in millions)			(in millions)	
Energy-related derivatives:	Other regulatory assets, current	$(13)	$(30)	Other regulatory liabilities, current	$3	$6

	Other regulatory assets, deferred	(8)	(15)	Other deferred credits and liabilities	2	5
Total energy-related derivative gains (losses)		$(21)	$(45)		$5	$11

II-275

NOTES (continued)
Georgia Power Company 2013 Annual Report

For the years ended December 31, 2013, 2012, and 2011, the pre-tax effects of interest rate derivatives designated as cash flow hedging instruments recognized in OCI and those reclassified from accumulated OCI into income were immaterial.

There was no material ineffectiveness recorded in earnings for any period presented. The pre-tax effect of energy-related derivatives not designated as hedging instruments on the statements of income was immaterial for all years presented.

Contingent Features

The Company does not have any credit arrangements that would require material changes in payment schedules or terminations as a result of a credit rating downgrade. There are certain derivatives that could require collateral, but not accelerated payment, in the event of various credit rating changes of certain affiliated companies. At December 31, 2013, the fair value of derivative liabilities with contingent features was $3 million.

At December 31, 2013, the Company had no collateral posted with its derivative counterparties; however, because of the joint and several liability features underlying these derivatives, the maximum potential collateral requirements arising from the credit-risk-related contingent features, at a rating below BBB- and/or Baa3, were $9 million. 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.

Generally, collateral may be provided by a Southern Company guaranty, letter of credit, or cash. The Company participates in 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.

The Company is exposed to losses related to financial instruments in the event of counterparties' nonperformance. The Company only enters into agreements and material transactions with counterparties that have investment grade credit ratings by Moody's Investors Services, Inc. and Standard and Poor's Ratings Services, a division of The McGraw Hill Companies, Inc. or with counterparties who have posted collateral to cover potential credit exposure. The Company has also established risk management policies and controls to determine and monitor the creditworthiness of counterparties in order to mitigate the Company's exposure to counterparty credit risk. Therefore, the Company does not anticipate a material adverse effect on the financial statements as a result of counterparty nonperformance.

NOTES (continued)
Georgia Power Company 2013 Annual Report

12. QUARTERLY FINANCIAL INFORMATION (UNAUDITED)
Summarized quarterly financial information for 2013 and 2012 is as follows:

Quarter Ended	Operating Revenues	Operating Income	Net Income After Dividends on Preferred and Preference Stock
	(in millions)		
March 2013	$1,882	$412	$197
June 2013	2,042	552	282
September 2013	2,484	872	487
December 2013	1,866	404	208
March 2012	$1,745	$344	$167
June 2012	2,020	535	295
September 2012	2,498	924	525
December 2012	1,735	400	181

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

Table of Contents Index to Financial Statements

SELECTED FINANCIAL AND OPERATING DATA 2009-2013
Georgia Power Company 2013 Annual Report

	2013	2012	2011	2010	2009
Operating Revenues (in millions)	$8,274	$7,998	$8,800	$8,349	$7,692
Net Income After Dividends on Preferred and Preference Stock (in millions)	$1,174	$1,168	$1,145	$950	$814
Cash Dividends on Common Stock (in millions)	$907	$983	$1,096	$820	$739
Return on Average Common Equity (percent)	12.45	12.76	12.89	11.42	11.01
Total Assets (in millions)	$28,907	$28,803	$27,151	$25,914	$24,295
Gross Property Additions (in millions)	$1,906	$1,838	$1,981	$2,401	$2,646
Capitalization (in millions):					
Common stock equity	$9,591	$9,273	$9,023	$8,741	$7,903
Preferred and preference stock	266	266	266	266	266
Long-term debt	8,633	7,994	8,018	7,931	7,782
Total (excluding amounts due within one year)	$18,490	$17,533	$17,307	$16,938	$15,951
Capitalization Ratios (percent):					
Common stock equity	51.9	52.9	52.1	51.6	49.5
Preferred and preference stock	1.4	1.5	1.5	1.6	1.7
Long-term debt	46.7	45.6	46.4	46.8	48.8
Total (excluding amounts due within one year)	100.0	100.0	100.0	100.0	100.0
Customers (year-end):					
Residential	2,080,358	2,062,040	2,047,390	2,049,770	2,043,661
Commercial	299,340	297,294	296,143	296,140	295,375
Industrial	8,216	8,246	8,279	8,136	8,202
Other	8,623	7,724	7,521	7,309	6,580
Total	2,396,537	2,375,304	2,359,333	2,361,355	2,353,818
Employees (year-end)	7,886	8,094	8,310	8,330	8,599

Table of Contents Index to Financial Statements

SELECTED FINANCIAL AND OPERATING DATA 2009-2013 (continued)
Georgia Power Company 2013 Annual Report

	2013	2012	2011	2010	2009
Operating Revenues (in millions):					
Residential	$3,058	$2,986	$3,241	$3,072	$2,686
Commercial	3,077	2,965	3,217	3,011	2,826
Industrial	1,391	1,322	1,547	1,441	1,318
Other	94	89	94	84	82
Total retail	7,620	7,362	8,099	7,608	6,912
Wholesale — non-affiliates	281	281	341	380	395
Wholesale — affiliates	20	20	32	53	112
Total revenues from sales of electricity	7,921	7,663	8,472	8,041	7,419
Other revenues	353	335	328	308	273
Total	$8,274	$7,998	$8,800	$8,349	$7,692
Kilowatt-Hour Sales (in millions):					
Residential	25,479	25,742	27,223	29,433	26,272
Commercial	31,984	32,270	32,900	33,855	32,593
Industrial	23,087	23,089	23,519	23,209	21,810
Other	630	641	657	663	671
Total retail	81,180	81,742	84,299	87,160	81,346
Wholesale — non-affiliates	3,029	2,934	3,904	4,662	5,208
Wholesale — affiliates	496	600	626	1,000	2,504
Total	84,705	85,276	88,829	92,822	89,058
Average Revenue Per Kilowatt-Hour (cents):					
Residential	12.00	11.60	11.91	10.44	10.22
Commercial	9.62	9.19	9.78	8.89	8.67
Industrial	6.03	5.73	6.58	6.21	6.04
Total retail	9.39	9.01	9.61	8.73	8.50
Wholesale	8.54	8.52	8.23	7.65	6.57
Total sales	9.35	8.99	9.54	8.66	8.33
Residential Average Annual Kilowatt-Hour Use Per Customer	12,293	12,509	13,288	14,367	12,848
Residential Average Annual Revenue Per Customer	$1,475	$1,451	$1,582	$1,499	$1,314
Plant Nameplate Capacity Ratings (year-end) (megawatts)	17,586	17,984	16,588	15,992	15,995
Maximum Peak-Hour Demand (megawatts):					
Winter	12,767	14,104	14,800	15,614	15,173
Summer	15,228	16,440	16,941	17,152	16,080
Annual Load Factor (percent)	63.5	59.1	59.5	60.9	60.7
Plant Availability (percent)*:					
Fossil-steam	87.1	90.3	88.6	88.6	92.5
Nuclear	91.8	94.1	92.2	94.0	88.4
Source of Energy Supply (percent):					
Coal	26.4	26.6	44.4	51.8	52.3
Nuclear	17.7	18.3	16.6	16.4	16.2

Hydro	2.0	0.7	1.1	1.4	1.8
Oil and gas	29.6	22.0	8.9	8.0	7.7
Purchased power -					